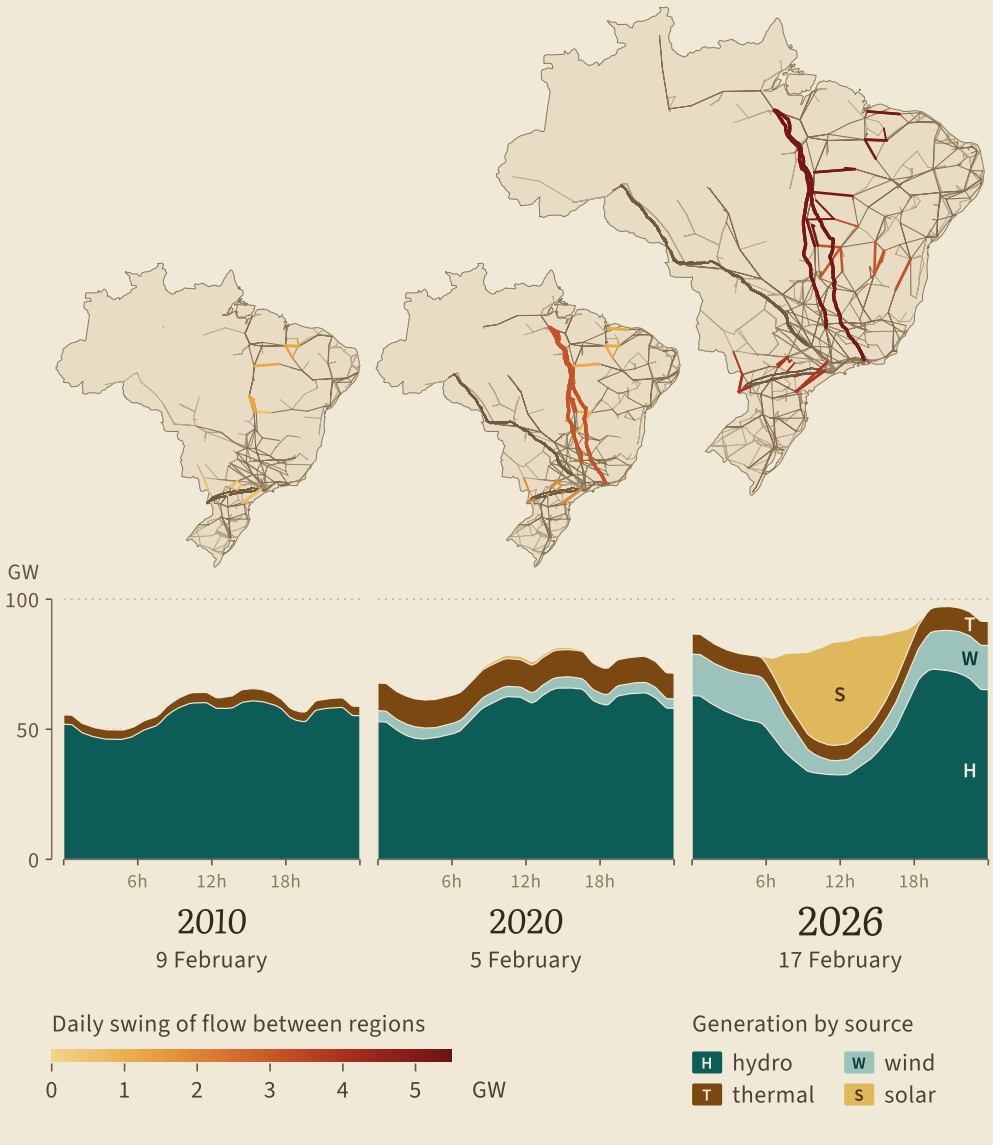
ALEXANDRE STREET

A Short History of the

Brazilian Electricity Market

and the Loss of Flexibility

Collected opinion articles, 2014–2026



A Short History of the Brazilian Electricity Market and the Loss of Flexibility

Collected opinion articles, 2014–2026

Alexandre Street

2026

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English edition, 2026

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Latest version: lampspuc.github.io/brazil-electricity-market-history/en

alexandrestreet.com

About the sources

I wrote all the articles in this book alone. They were published in the newspapers, magazines, and social media listed on my website, at alexandrestreet.com/opinion. That page is the source of record for the collection. The Subsidies Series 2026, which I wrote with colleagues of the National Academy of Engineering, is a collective work and will be published separately.

Each article opens with its date, its outlet, and a link to the published version, and articles translated from Portuguese also show their original title. The articles appeared in O Globo, Valor Econômico, CanalEnergia, MegaWhat, CNN Brasil, Brazil Journal, and LinkedIn. Those first published in Portuguese appear here in English translation. *When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market*, the article that opens the book, was written in English and published on LinkedIn on 7 March 2026. It has a shorter Portuguese companion, *A urgente reforma do setor elétrico*, published in Valor Econômico on 24 February 2026. For the Valor Econômico articles of 2024 to 2026, the text follows the manuscript linked on the same page.

Acronyms are spelled out at first use in every text, so that each article and each chapter introduction can be read on its own. A list of acronyms follows the timeline. One erratum is noted in a footnote where it applies.

The book can be read in three ways. The chapter introductions, read alone, tell the whole story, with the core ideas and conclusions of each period. The abstract at the head of each article gives its reasoning and its conclusion in about two hundred words. The full texts give each argument as it was published, with the numbers available at the time.

Contents

About the sources iii
List of articles vii
Key topics at a glance x
Preface — Markets by design xvii
A timeline drawn from the articles xxii
Acronyms xxv

Chapter 1
When Prices Stop Telling the Truth *2026* 1
When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6

Chapter 2
A System Designed for Water *2014–2015* 15
A Problem of Water Management 20
The Energy Crisis of 2015 23
Time to Review the Operation and Expansion of the Power Sector 27

Chapter 3
The Lost Coherence: Models, Institutions and the Repeated Crisis *2016–2021* 31
The Welcome Review of the Method for Calculating Electricity Prices 36
Metrics for Evaluation and Monitoring 40
The Electricity Market and Institutional Restructuring 43
The Inconsistency of the Power Sector and the Repeated Crisis 47

Chapter 4
Pricing Time: From Hourly Prices to Ancillary Services *2018–2024* 51
Hourly Prices: Opportunities and Challenges 56
The New Components of the Electricity Price in 2021 60
Rethinking Energy Management and the Role of Generation Sources 64

Chapter 5
Expansion by Subsidy and the Consumer's Response *2024–2025* 68
Revolution in Electricity Retail Challenges Regulation 72
The Saga of Subsidy-Driven Expansion in the Power Sector 76

Chapter 6
In Search of Lost Flexibility *2025* 80
In Search of Lost Flexibility 85
Pricing Energy and Flexibility in the Electricity Market 91

Chapter 7
Neither Market nor Planning: The Capacity Auctions of 2026 *2026* 95
Neither Market nor Planning: Expansion Is by Subsidy 100
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Power Sector and the Land of Lost Opportunities 114
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118

Chapter 8
A Myopic and Incomplete Price System *2026* 123
The Confusion over Prices and Risk Aversion in the Power Sector 128
From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133

Chapter 9
Institutions, the Consumer and Justice *2026* 139
The Two Absurdities about Itaipu 144
Electricity Reform as Social Justice 148

The Institutional Deterioration of the Brazilian Electricity Sector 152

Chapter 10

An Agenda for 2027 *2026* 157

An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Afterword — Looking ahead 167

List of articles

In order of publication. Each title leads to the article in this book; the last column links to the published version.

Date	Title / Outlet	Published version
14 Oct 2014	A Problem of Water Management O Globo	oglobo.globo.com
24 Feb 2015	The Energy Crisis of 2015 Valor Econômico	lamps.ind.puc-rio.br
27 Nov 2015	Time to Review the Operation and Expansion of the Power Sector Valor Econômico	drive.google.com
1 Sep 2016	The Welcome Review of the Method for Calculating Electricity Prices Valor Econômico	lamps.ind.puc-rio.br
21 Feb 2018	Hourly Prices: Opportunities and Challenges CanalEnergia	canalenergia.com.br
15 Jan 2019	Metrics for Evaluation and Monitoring CanalEnergia	canalenergia.com.br
31 Jan 2019	The Electricity Market and Institutional Restructuring Valor Econômico	lamps.ind.puc-rio.br
14 Apr 2020	The New Components of the Electricity Price in 2021 Valor Econômico	valor.globo.com
16 Jun 2021	The Inconsistency of the Power Sector and the Repeated Crisis Valor Econômico	valor.globo.com

Date	Title / Outlet	Published version
23 Apr 2024	Rethinking Energy Management and the Role of Generation Sources Valor Econômico	valor.globo.com
19 Jun 2024	Revolution in Electricity Retail Challenges Regulation Valor Econômico	valor.globo.com
14 Feb 2025	The Saga of Subsidy-Driven Expansion in the Power Sector Valor Econômico	valor.globo.com
7 Mar 2025	In Search of Lost Flexibility MegaWhat	megawhat.energy
25 Aug 2025	Pricing Energy and Flexibility in the Electricity Market Valor Econômico	valor.globo.com
7 Mar 2026	When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market LinkedIn	linkedin.com
20 Mar 2026	The Two Absurdities about Itaipu MegaWhat	megawhat.uol.com.br
25 Mar 2026	Neither Market nor Planning: Expansion Is by Subsidy CNN Brasil	cnnbrasil.com.br
24 Apr 2026	The Confusion over Prices and Risk Aversion in the Power Sector LinkedIn	linkedin.com
20 May 2026	Five Problems with Brazil's 2026 Capacity Reserve Auction LinkedIn	linkedin.com
9 Jun 2026	The Power Sector and the Land of Lost Opportunities Valor Econômico	valor.globo.com
25 Jun 2026	From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System LinkedIn	linkedin.com

Date	Title / Outlet	Published version
26 Jun 2026	Electricity Reform as Social Justice Brazil Journal	braziljournal.com
2 Jul 2026	The Institutional Deterioration of the Brazilian Electricity Sector CNN Brasil	cnnbrasil.com.br
19 Aug 2026	The Regulatory Barrier in Brazil's Power Sector and the Battery Auction CNN Brasil	cnnbrasil.com.br
22 Oct 2026	An Agenda for Brazil's Electricity Sector from 2027 Onward CNN Brasil	cnnbrasil.com.br

Key topics at a glance

Fourteen topics recur across the articles. For each one, I describe below how the book treats it, and the articles where it appears follow.

Flexibility

Flexibility is the ability of plants, storage, and consumers to change output or consumption quickly and keep the system in balance. Brazil lost the flexibility its reservoirs once supplied without a price, and I argue that it must now be priced separately from energy.

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6
Time to Review the Operation and Expansion of the Power Sector 27
Hourly Prices: Opportunities and Challenges 56
The New Components of the Electricity Price in 2021 60
Rethinking Energy Management and the Role of Generation Sources 64
The Saga of Subsidy-Driven Expansion in the Power Sector 76
In Search of Lost Flexibility 85
Pricing Energy and Flexibility in the Electricity Market 91
The Power Sector and the Land of Lost Opportunities 114
An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Subsidies

Subsidies meant to give wind and solar an initial push turned into a mechanism that produces the next subsidy. The Energy Development Account, the triple subsidy to non-controllable renewables, and the capacity auctions by source are the main cases.

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6
Revolution in Electricity Retail Challenges Regulation 72
The Saga of Subsidy-Driven Expansion in the Power Sector 76
Pricing Energy and Flexibility in the Electricity Market 91
Neither Market nor Planning: Expansion Is by Subsidy 100
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118
The Two Absurdities about Itaipu 144
Electricity Reform as Social Justice 148
The Institutional Deterioration of the Brazilian Electricity Sector 152

Short-term prices

The short-term price settles every difference between what agents contracted and what they actually generated or consumed, and it is the cornerstone of the market. It moved from weekly to hourly values in 2021. Because it is still fixed a day in advance and ignores the network, it does not tell the truth about the operation.

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6
A Problem of Water Management 20
The Welcome Review of the Method for Calculating Electricity Prices 36
The Inconsistency of the Power Sector and the Repeated Crisis 47
Hourly Prices: Opportunities and Challenges 56
The New Components of the Electricity Price in 2021 60
Rethinking Energy Management and the Role of Generation Sources 64
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118
The Confusion over Prices and Risk Aversion in the Power Sector 128
From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133

Capacity auctions

Capacity contracts pay plants for being available, while the consumer still buys their energy separately. I analyze the auction of March 2026, its price, its incentive problems, and the battery auction that came after it.

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6
The Saga of Subsidy-Driven Expansion in the Power Sector 76
In Search of Lost Flexibility 85
Pricing Energy and Flexibility in the Electricity Market 91
Neither Market nor Planning: Expansion Is by Subsidy 100
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Power Sector and the Land of Lost Opportunities 114
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118
The Institutional Deterioration of the Brazilian Electricity Sector 152
An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Ancillary services

Ancillary services, such as reserves and frequency regulation, act within milliseconds to minutes to keep the system in balance. They must be priced, co-optimized with energy, and paid on an equal footing to every source that provides them.

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6
Hourly Prices: Opportunities and Challenges 56
Rethinking Energy Management and the Role of Generation Sources 64
Pricing Energy and Flexibility in the Electricity Market 91
From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133
An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Two-settlement and real time

In a two-settlement system, the day-ahead market forms a first settlement, and each deviation from it is settled again at the real-time price. With prices every ten minutes, it is the core of the reform I propose for the short-term market.

The New Components of the Electricity Price in 2021 60
In Search of Lost Flexibility 85
Pricing Energy and Flexibility in the Electricity Market 91
From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133
The Institutional Deterioration of the Brazilian Electricity Sector 152
An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Distributed generation and retail

Distributed generation showed consumers escaping a regulated segment through its loopholes. Retail opening, distribution networks, and the remuneration of distribution companies belong to the same market design.

Revolution in Electricity Retail Challenges Regulation 72
In Search of Lost Flexibility 85
The Power Sector and the Land of Lost Opportunities 114
Electricity Reform as Social Justice 148
An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Demand response and distributed flexibility

Demand response, from the 2001 rationing to the program created in 2022, is my main evidence that consumers respond to prices. I propose to extend it into distributed flexibility, with aggregators and local flexibility markets.

Revolution in Electricity Retail Challenges Regulation 72
In Search of Lost Flexibility 85
The Power Sector and the Land of Lost Opportunities 114

From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133
Electricity Reform as Social Justice 148

Batteries and storage

Batteries appear both as the technology that well-designed prices attract on their own, as in Texas, and as the next candidate for a subsidy through the battery auction of 2026.

The Power Sector and the Land of Lost Opportunities 114
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118
The Institutional Deterioration of the Brazilian Electricity Sector 152

Models and risk aversion

Dispatch and prices in Brazil come from official optimization models. I follow their optimistic biases, the inconsistency between long- and short-term models, and a risk-aversion metric without parallel among the world's system operators.

A Problem of Water Management 20
The Energy Crisis of 2015 23
Time to Review the Operation and Expansion of the Power Sector 27
The Welcome Review of the Method for Calculating Electricity Prices 36
Metrics for Evaluation and Monitoring 40
The Electricity Market and Institutional Restructuring 43
The Inconsistency of the Power Sector and the Repeated Crisis 47
Hourly Prices: Opportunities and Challenges 56
The Confusion over Prices and Risk Aversion in the Power Sector 128

Hydro and water value

Hydro plants and the water value, which measures how much stored water reduces the future cost of supply, are the foundation of the Brazilian design. The book covers the crises of water management, the role of reservoirs in absorbing the variability of renewables, and the unpaid flexibility of hydro plants.

A Problem of Water Management 20
The Energy Crisis of 2015 23
Time to Review the Operation and Expansion of the Power Sector 27
Metrics for Evaluation and Monitoring 40
The Inconsistency of the Power Sector and the Repeated Crisis 47
Rethinking Energy Management and the Role of Generation Sources 64
The Confusion over Prices and Risk Aversion in the Power Sector 128
From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133

Institutions and governance

Institutions determine whether prices are allowed to reflect the operation. I discuss who controls the models, the separation of operator and planner, the single buyer, neglected budgets, and, at bottom, leadership.

A Problem of Water Management 20
The Energy Crisis of 2015 23
Time to Review the Operation and Expansion of the Power Sector 27
The Welcome Review of the Method for Calculating Electricity Prices 36
Metrics for Evaluation and Monitoring 40
The Electricity Market and Institutional Restructuring 43
The Inconsistency of the Power Sector and the Repeated Crisis 47
Revolution in Electricity Retail Challenges Regulation 72
The Saga of Subsidy-Driven Expansion in the Power Sector 76
Neither Market nor Planning: Expansion Is by Subsidy 100
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Two Absurdities about Itaipu 144
Electricity Reform as Social Justice 148
The Institutional Deterioration of the Brazilian Electricity Sector 152

Crises and rationing

The rationing of 2001, the crises of 2014–2015 and 2021, and the blackout of 15 August 2023 are the milestones of this history. I read most of them

as the result of models, prices, or rules that had drifted away from the real operation.

A Problem of Water Management 20
The Energy Crisis of 2015 23
The Inconsistency of the Power Sector and the Repeated Crisis 47

International lessons

International experience appears as lessons from Texas, California, and PJM Interconnection, markets roughly fifteen years ahead of Brazil, with the caution that none of them is an example of great virtue.

The Electricity Market and Institutional Restructuring 43
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118

Preface — Markets by design

Electricity markets are designed. They are built on top of physical systems governed by the laws of physics, in which supply and demand must balance every second and power flows follow the constraints of the network. In such systems, scarcity is shaped by time, location, and flexibility as much as by installed capacity. The sector also involves many externalities that require specific designs, so a market for electricity does not arise naturally in a form that serves the system. Someone has to decide what is traded, how prices are formed, who contracts with whom, and who pays for what. These decisions make up the market design.

Each design answers to the needs of a place. Every country or state has its own climate and resource availability, its own pace of demand growth, its own history and political goals, and even its own culture and social moral standards. For this reason no two electricity markets in the world are the same. There is no such thing as the best market design. There are better designs and lessons learned, and market design is a work in progress that never ends, because technologies, economies, political goals, and the climate itself keep changing. In Frank Wolak's words, "Understanding the incentives created by different market designs is essential to designing a reliable, low cost and low carbon electricity supply."

Design cannot, however, keep markets from forming. Markets form wherever there is scarcity and people are free to cooperate and exchange. Brazilian households showed this when they built a market for distributed-generation credits inside a segment designed on the assumption that no market could exist there, a story I told in *Revolution in Electricity Retail Challenges Regulation*. The design decides whether what emerges serves the system or works against it.

Latin America has faced rapid load growth, and the region answered with three instruments: (1) long-term contracts that stabilize revenues and give incentives to invest, (2) a regulatory framework that ties the growth of demand to the construction of new generation, and (3) systematic contracting through auctions, which reduces costs, coordinates the contracting of load, and ensures liquidity. This is the region's strength. Its experience with short-term incentives and with the integration of intermittent renewables is limited. The connection between short-term prices and real-time operation is weak, and solar and wind have expanded on the basis of subsidies. The United States, in contrast, has a long history of trying to get short-term prices right.

The Brazilian design

Brazil designed its market for a system that was about 90% hydroelectric. Hydro is a renewable source that can be controlled. Its reservoirs delivered energy and, at no apparent cost, the flexibility the operator needed to balance supply and demand from one moment to the next. Scarcity in that system meant a shortage of water over months and years, so the design priced energy and treated flexibility as part of the same package. Dispatch and the short-term price were computed by official optimization models. These models estimate the future value of the water in the reservoirs and decide how much of it to use today. As I wrote in *The Energy Crisis of 2015*, the country depends on managing the water stored in its reservoirs, and therefore on how faithfully those models represent the system.

The reform of 2004 completed this design. It followed the rationing crisis of 2001 and established three guidelines. All load had to be contracted. Every contract had to be backed by a physical guarantee, an administratively calculated certificate of firm energy. And distribution companies could buy standardized long-term contracts only through centralized public auctions, organized by the Ministry of Mines and Energy as single-buyer procurement. The reform reconnected load growth with the long-term investment signal and opened a cycle of

robust and coordinated expansion that many Latin American countries followed.

What changed

The reality behind the design began to change around 2010. Construction of new storage reservoirs stopped, held back by environmental constraints and stricter licensing. Load kept growing, by about 45% between 2010 and 2024. Wind and solar, encouraged by subsidies, filled the gap. Renewables kept roughly their share of generation, 87% in 2024 against the 89% that hydro plants alone had produced in 2010. The share of non-controllable sources, however, rose from less than 1% of total generation in 2010 to 30% of the renewable share in 2024. As I put it in *The Saga of Subsidy-Driven Expansion in the Power Sector*, these sources supply energy but consume flexibility. The system remained renewable and lost controllability.

The design did not change with the system. The short-term price is still computed the day before operation and without representing the network. The ancillary services that balance the system within seconds and minutes are not priced. Wind and solar received three subsidies, which inflated their "perceived price" relative to competing technologies and fueled an expansion without economic discipline. Once the market stopped paying for what had become scarce, the operator kept the system in balance through actions that never reached the price. Thermal plants were dispatched outside the merit order, hydro plants absorbed solar ramps without explicit payment, and the costs were passed on to consumers through charges. Prices stopped telling the truth about the operation.

From then on, each correction created the need for another. Consumers pay sector subsidies in their tariffs through the Energy Development Account, which grew at an average of 16.5% a year from 2004 onward. Capacity auctions for specific sources were proposed to correct the imbalance that subsidies to other sources had created, and a battery auction followed the capacity auction of 2026. This is what I mean by the loss of flexibility in the title of this book. A system that

once had flexibility in abundance now lacks it, has no price to reveal its value, and pays for it through subsidies, charges, and long-term contracts.

The plan of the book

The book collects twenty-five articles I published between 2014 and 2026. It opens with a synthesis I wrote in March 2026, *When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market*, because that article states in one piece the argument the others build step by step. From the second chapter on, the book follows the order of publication, so that the reader sees the argument take shape as events unfolded. In 2026, the year in which I wrote most, the chapters group the articles by theme and overlap by a few months.

1. Chapter 1 states the thesis and the reform agenda through the article of March 2026.
2. Chapter 2 returns to the crisis of 2014–2015 in a system designed for water and run by models that were always more optimistic than reality.
3. Chapter 3 follows the lost coherence between models, institutions, and operation, from 2016 to the repeated crisis of 2021.
4. Chapter 4 covers the move from weekly to hourly prices and the case for pricing ancillary services and flexibility.
5. Chapter 5 shows consumers responding to prices through distributed generation while subsidies breed further subsidies.
6. Chapter 6 dates the loss of flexibility and shows where it can be recovered, in real-time markets, in demand response, and in distribution networks.
7. Chapter 7 analyzes the capacity reserve auction of March 2026 and the battery auction that followed.
8. Chapter 8 diagnoses a price system that is myopic and incomplete.
9. Chapter 9 turns to institutions, the consumer, and justice, from Itaipu to the weakening of the sector's institutions.

10. Chapter 10 closes with the agenda I proposed for the next government, which begins in 2027.

In all of these chapters I defend the same idea. Prices must tell the truth about the operation of the system, to connect the market, and its incentives, to the needs of the system. When they do, investors and entrepreneurs direct capital, technology, and intelligence toward where economic value is highest. When they do not, the costs of what the system needs reappear in subsidies, charges, and administrative contracts, where they no longer guide anyone's investment.

A timeline drawn from the articles

The events below are those dated in the articles themselves. Each is followed by the articles that report it.

2001 Brazil goes through an electricity rationing, and the Revitalization Committee studies its causes and lays the foundations of a new regulatory framework (p. 6).

2001 During the rationing, the Energy Efficiency Law (Law 10.295/2001) sets minimum efficiency levels for equipment, and consumers themselves choose more efficient appliances (p. 118).

2002 Law 10.438 creates the Energy Development Account, with a budget adjusted to market growth and an end date in 2027 (p. 76).

2004 The new regulatory framework requires all load to be contracted, every contract to be backed by a physical guarantee, and distribution companies to buy through centralized auctions. The system is 90% hydroelectric (pp. 6, 91).

2005 From this year on, practically every new-energy auction restricts competition by technology (p. 152).

2010 Hydro plants produce about 89% of generation and non-controllable renewables less than 1% of total generation, and Brazil begins to encourage wind and solar farms (pp. 76, 85).

2012 Storage falls from a record above 70% to a record low of about 30%, with inflows only slightly below average (p. 23).

2013 Provisional Measure 579 (Law 12.783) eliminates the end date of the Energy Development Account and adds new subsidies (p. 76).

2014 The short-term price has been at its cap since 2013. Major reservoirs approach zero, storage in the Southeast falls to about 25%, and the Treasury rescues the distribution companies (p. 20).

2015 Southeast reservoirs approach the critical safety limit of 10%, and consultants put the chance of rationing above 50% (p. 23).

2016 The Power Sector Monitoring Committee signals a review of the dispatch and price-formation methods (p. 36).

2017 Public Consultation No. 33, on the modernization of the power sector, sets the agenda for hourly prices and puts the discussion of a bid-based market on the table (pp. 56, 43).

2021 The spot price becomes hourly, still set a day ahead (pp. 60, 64).

27 May 2021 The Power Sector Monitoring Committee meets in an extraordinary session on a new water crisis, with Southeast reservoirs at about 32% (p. 47).

2022 Normative Resolution No. 1.040/2022 of the Brazilian Electricity Regulatory Agency creates a voluntary demand-response program, which had already exceeded 9 GWh in October 2024 (p. 85).

2022 An interpretation of the legal framework boosts the sale of distributed-generation credits within the regulated market (p. 6).

2023 Itaipu's debt is fully repaid, and the tariff should fall (p. 144).

15 August 2023 A blackout affects 25 states and the Federal District (p. 85).

2024 The Energy Development Account reaches a little over R$40 billion, and non-controllable sources reach 30% of the renewable share of generation (p. 76).

2025 The National Electric System Operator estimates a 96% probability of loss of load from insufficient capacity by 2029 (p. 114).

December 2025 The Electric Reliability Council of Texas introduces the co-optimization of energy and ancillary services (p. 162).

17 February 2026 Solar generation peaks at 40 GW around midday, and hydro plants absorb the evening ramp (p. 6).

18 March 2026 The capacity reserve auction contracts 18,977 MW at about R$38.9 billion a year (p. 100).

30 July 2026 The public consultation on the first battery auction of the national system opens (p. 118).

2027 A new government begins its term, in the year originally set for the end of the Energy Development Account (pp. 162, 76).

Acronyms

ABIAPE	Brazilian Association of Investors in Energy Self-Production
ACL	free contracting environment, the free market, in which consumers choose their supplier
ACR	regulated contracting environment, in which captive consumers buy from the local distribution company at a regulated tariff
ANEEL	Brazilian Electricity Regulatory Agency
BNDES	Brazilian Development Bank
CAISO	California Independent System Operator
CAPEX	capital expenditure
CCEE	Electric Energy Trading Chamber, the market operator, which computes the spot price and settles the market
CDE	Energy Development Account, the fund through which sector subsidies are passed on to consumers in their tariffs
Cepel	Electric Energy Research Center, the research arm of Eletrobras, which maintains the official models
CMSE	Power Sector Monitoring Committee
COVID-19	coronavirus disease 2019
CP 33	Public Consultation No. 33, of 2017, on the modernization of the power sector
CVaR	conditional value-at-risk, the risk measure that the official models apply, in nested form, to total operating cost
DESSEM	the day-ahead scheduling model maintained by Cepel

DG	distributed generation
DR	demand response
DSO	distribution system operator
EPE	Brazilian Energy Planning Agency
ERCOT	Electric Reliability Council of Texas, the system operator of Texas
FERC	Federal Energy Regulatory Commission, the federal energy regulator of the United States
FGTS	Severance Indemnity Fund
GSF	generation scaling factor
Inpe	National Institute for Space Research
IPCA	official consumer price index
LAMPS	Laboratory of Applied Mathematical Programming and Statistics, PUC-Rio
LATAM	Latin America
LRCAP	capacity reserve auction
MME	Ministry of Mines and Energy
Newave	the long- and medium-term planning model maintained by Cepel
ONS	National Electric System Operator
PJM	PJM Interconnection, in the United States
PLD	spot price, the settlement price for differences between contracts and actual generation or consumption
Procel	National Electricity Conservation Program
PUC-Rio	Pontifical Catholic University of Rio de Janeiro
SAR	risk-aversion surface, a minimum storage level for a given time of the year
US$	United States dollar

Chapter 1

When Prices Stop Telling the Truth

2026

In this chapter

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market 6

Introduction

On 17 February 2026, solar generation in Brazil peaked at 40 GW around midday. Hydroelectric plants cut their output while the sun was high and ramped up quickly in the evening, when solar output fell sharply at sunset. This service is what we call flexibility, and it kept the system in balance that day. The spot price did not value it adequately. The price is set one day in advance, and many of the actions the operator took in real time to manage the variation never reached price formation. This single day of operation contains the argument of this book, and I open with the article that tells its story because it states in one piece the thesis that the following chapters, from 2014 to 2026, reach step by step.

The argument starts from physics, because an electricity market is built on top of a physical system that must match supply and demand every second, with power flowing as the network allows. Scarcity is therefore shaped by time, location, and flexibility as much as by installed capacity, and a good design internalizes what is truly scarce so that agents receive the right signals. Each country has its own climate, resources, history, institutions, and political objectives, so no two electricity markets are the same and no single design is best for all. Adaptation is part of design, but small interventions can change incentives deeply, and subsidies call for particular care.

Short-term prices are the cornerstone of this structure. Even in a market built on long-term contracts, as Brazil's is, every difference between contracted volumes and actual generation or consumption is settled at the spot price. Renewable generators that were recently curtailed, or, as I prefer to say, not dispatched, kept their contract revenue and still lost large sums in that settlement. When the link between prices and operation breaks, the system keeps operating, but the market stops paying for what is scarce. I call this broken link the "root of all evil". The operator soon has too much of what it does not need and too little of what it needs, and demands for subsidies, auctions by technology, lawsuits, weaker institutions, and regulatory capture follow.

In Brazil the link broke on several fronts. Reservoir construction stopped, and wind and solar, which supply energy but consume

flexibility, took the place of hydro in the expansion. Prices are still set a day ahead, and ancillary services have no price. These are the reserves and fast adjustments that keep the system stable from milliseconds to minutes. Three subsidies inflated the "perceived price" of renewables relative to competing technologies. The Energy Development Account, through which these subsidies reach consumers' tariffs, has grown 16.5% a year on average. From 2022, the sale of distributed-generation credits inside the regulated market challenged a design that failed to adapt and, as a consequence, lost its capacity for self-regulation. By the end of 2025, competition had become a race for the next subsidy. I set this against the 2004 reform, which reconnected load growth with investment, and close the article with a structural agenda.

Core ideas

1. Electricity markets are built on top of physical systems, where scarcity is shaped by time, location, and flexibility as much as by installed capacity, and their design must internalize what is truly scarce.
2. No two electricity markets are alike, and there is no single best design. Adaptation is part of design, but small interventions, subsidies above all, can turn incentives against their purpose.
3. Short-term prices are the cornerstone even of a market built on long-term contracts, because every deviation from a contract is settled at the spot price.
4. The broken link between prices and operation is the "root of all evil", because the operator then gets too much of what it does not need and too little of what it needs, and subsidies, technology-specific auctions, lawsuits, and regulatory capture follow.
5. In Brazil, reservoir construction stopped, wind and solar expanded, and prices are still set a day ahead with no price for ancillary services, so the price undervalued the flexibility hydro plants provided to absorb the 40 GW solar ramp of 17 February 2026.

6 Three subsidies inflated the "perceived price" of renewables and the Energy Development Account grew 16.5% a year, until competition became a race for the next subsidy.

7 The 2004 reform, with all load contracted, every contract backed by a physical guarantee, and centralized auctions, reconnected load growth with investment and was followed by many Latin American countries.

8 The structural agenda is to reduce subsidies, align spot prices with real time, create ancillary-service markets, develop risk-management instruments, and integrate distribution operators with the national operator. Capacity auctions, as proposed, only add one more layer of subsidy.

Conclusions

The Brazilian shortage of flexibility is, at its root, a problem of market design. When prices stop reflecting the operation, contracts, auctions, and subsidies lose their connection to what the system needs. The remedy therefore starts with prices that show how the system really operates. Capacity auctions that skip this step only add a layer of subsidy that will later require correction.

The articles

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market is the only article of this chapter. I wrote it in English for LinkedIn, where it appeared on 7 March 2026, after a shorter Portuguese version of the same argument, *A urgente reforma do setor elétrico*, had been published in Valor Econômico on 24 February. The article moves from principle to evidence. It explains why short-term prices are the cornerstone of electricity markets and documents the Brazilian case with three figures. They show the gap between day-ahead prices and the marginal cost of the generation actually dispatched, the solar and hydro profiles of 17 February 2026, and the growth of the

Energy Development Account. The article then recalls the 2004 reform and ends with the agenda to which Chapter 10 returns.

When Prices Stop Telling the Truth: The Urgent Reform of the Brazilian Electricity Market

LinkedIn · 7 March 2026
Published version: linkedin.com
Companion article: *A urgente reforma do setor elétrico*, Valor Econômico, 24 February 2026

ABSTRACT

Electricity markets are built on top of physical systems, where scarcity is shaped by time, location, and flexibility as much as by installed capacity, and their design must internalize what is truly scarce. Short-term prices are its cornerstone, even in markets based on long-term contracts, because deviations from contracts are settled at the spot price. When prices lose their link to the operation, markets stop paying for what is scarce. I call this broken link the "root of all evil". The operator then has too much of what it does not need and too little of what it does. In Brazil, reservoir construction stopped, wind and solar expanded, and prices are still set one day ahead, with ancillary services unpriced. On 17 February 2026, hydro plants absorbed a 40 GW solar ramp, a flexibility service that day-ahead prices undervalue. Three subsidies inflated the perceived price of renewables, and the Energy Development Account has grown 16.5% a year on average. The design lost its capacity for self-regulation, and competition became a race for the next subsidy. The 2004 reform reconnected load growth with investment. The structural agenda is to reduce subsidies, align spot prices with real time, create ancillary-service markets, develop risk-management instruments and integrate distribution operators with the national operator. Capacity auctions, as proposed, only add another layer of subsidies.

Electricity markets are unique because they are built on top of physical systems governed by the laws of physics, not by contracts or political

will. Supply and demand must be balanced every second, power flows follow network constraints rather than contractual paths, and scarcity is shaped by time, location, and flexibility as much as by installed capacity. Market design must therefore acknowledge these physical realities and internalize what is truly scarce in order to communicate the right signals to agents. At the same time, electricity markets are also designed to address specific challenges and regional realities.

Because each country or state has its own climate and resource availability, as well as its own history, institutions, and political objectives, no two electricity markets in the world are the same. For this reason, there is no such thing as a single best market design. There are better designs and lessons learned. And because technologies, economies, political priorities, and even the climate itself evolve over time, adaptation is not a failure of market design but an intrinsic part of it. Notwithstanding, precisely because market design operates by shaping incentives, care must be taken when adding even small features or regulatory interventions, as seemingly minor changes can fundamentally alter incentives, distort price signals, and produce outcomes that diverge sharply from their original intent. This is particularly critical when dealing with subsidies.

Short-term prices form the cornerstone of electricity markets and create the link between all other instruments and the system scarcities. When prices internalize the system's operational reality and reveal consumers' willingness to pay as well as the scarcity of network resources and generation technologies required to keep the system in balance, the entire economic–technological circuit is activated to correct short-term shortage or surplus. In a market where prices reflect the "pain points" of operational reality, investors and entrepreneurs respond by directing capital, technology, and intelligence toward where economic value is highest.

This holds true even in markets largely based on long-term forward contracts, because deviations between contracted volumes and actual consumption, or generation, are settled against short-term spot prices. Short-term spot prices, therefore, guarantee the link between the long-term contract market and its incentives and the system's short-term

operational needs in the future. If this does not seem obvious to the reader, one need only ask renewable generators that have recently been curtailed, or, as I prefer to name, not dispatched. While their contract revenues remain unchanged, they have lost enormous sums due to the settlement, at short-term prices, of the differences between their actual generation and their contractual positions. Unfortunately, Brazil provides many examples of this effect, with several generation companies contracting up to their maximum regulatory limit (close to their average production), thereby disregarding the importance of considering both the feasibility and the captured price of their generation when setting long-term forward contract positions.

When the link between markets and operations is broken, operations will continue, but markets will no longer remunerate what is scarce or necessary. Especially in Latin American countries such as Brazil, but to some extent, it constitutes a big issue in any electricity market; this is the "root of all evil." In a short time, the system operator will face an excess of what it does not need and a shortage of what is necessary. From there, we already know how the story unfolds and how things deteriorate: demands for more subsidies, special rules and auctions by technology type, judicial disputes, weakening of sectoral institutions, and regulatory capture by groups with strong political influence. All of this has, to some extent, been justified by the alleged inability of the market to efficiently attract or restrain investment, as well as by opportunistic narratives that dominate the debate by exploiting conjunctural side effects unrelated to the real causes of the system's deterioration.

Moving from theory to the reality of the Brazilian electricity sector, the country has increasingly relied on intermittent renewable sources, such as wind and solar, following the halt in the construction of new reservoirs over the previous decade, as environmental constraints and stricter licensing requirements significantly limited the expansion of large hydro projects. Unlike other generation sources, solar and wind supply energy but consume system short-term flexibility due to the intermittent nature of their availability, something the current electricity market design in Brazil is still not prepared to handle.

In addition to the absence of prices for ancillary services, the sectoral model sets wholesale short-term electricity prices one day in advance. As a result, all errors between what was forecast and what actually materializes from one day to the next, as well as most of the costs of the operational actions taken to correct them, are settled outside the market. This is clear in Figure 1, where spot prices, set one day earlier, significantly diverge from real-time reality.

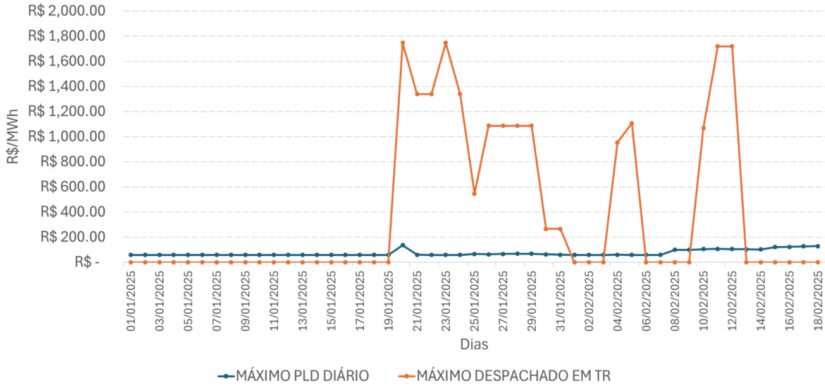


Figure 1 Spot prices (blue) and marginal cost of dispatched generation (orange). Source: Brazilian market and system operators, the Electric Energy Trading Chamber (CCEE) and the National Electric System Operator (ONS). US$1 ≈ R$5.

Under this design, agents that introduce uncertainty are not charged for the costs they impose, nor are those that help address it adequately remunerated. For example, as shown in Figure 2, on February 17, 2026, solar generation peaked at 40 GW around midday. At that time, hydroelectric generation was significantly reduced and later ramped up in the evening to compensate for the sharp drop in solar output at sunset. Despite its critical role in maintaining real-time system balance, this service, commonly referred to as flexibility, is not adequately valued in day-ahead spot prices, as many of the operational actions implemented in real time to manage the resulting net-load variation are not incorporated into the price formation process.

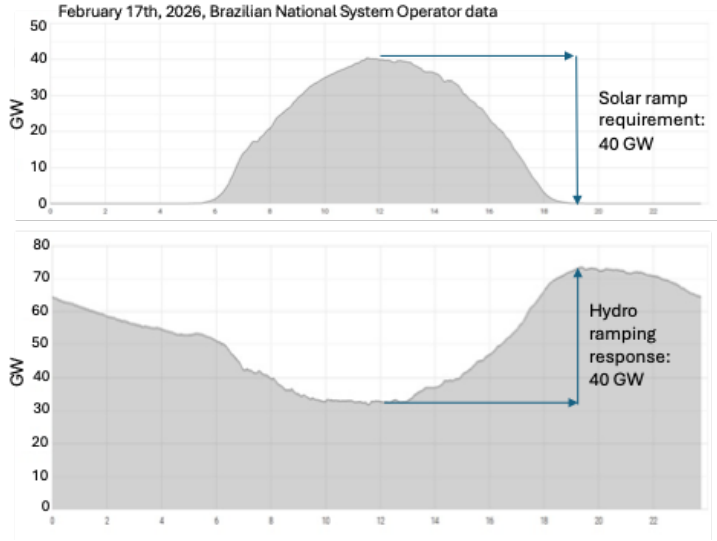


Figure 2 February 17th, 2026, Brazilian power system total solar and hydro generation. Source: Brazilian system operator (ONS).

Added to these distortions is the dangerous shortcut adopted through subsidies to ensure that renewable sources could be deployed and thrive relative to conventional generation. Today, renewables receive three types of subsidies: (1) a 50% discount on transmission tariffs, (2) exemption from contributing to ancillary services, and (3) exemption from paying for the additional costs imposed by their uncertainty. This set of subsidies overlaps with short-term prices that have already been stripped of any scarcity signals arising from the inflexibility created by these sources. The result has been the emergence of a systematically inflated "perceived price" relative to competing generation technologies, fueling an accelerated subsidized expansion of wind and solar generation without the economic discipline that a well-designed market should impose. Figure 3 illustrates the exponential growth in subsidies passed on to consumers through tariffs in Brazil. The Energy Development Account (CDE), largely driven by subsidies for renewables, has grown at an average annual rate of 16.5%.

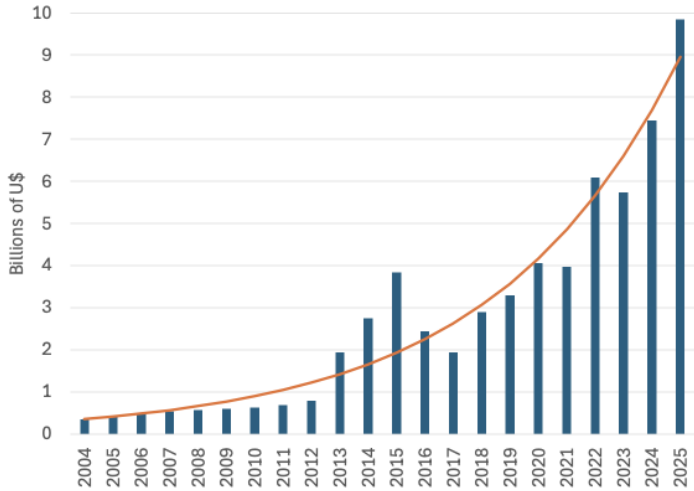


Figure 3 Brazilian Energy Development Account (CDE, in Portuguese): subsidies passed on to consumers through tariffs. Source: Brazilian Association of Investors in Energy Self-Production (ABIAPE).

From 2022 onward, as the cost of subsidies allocated to residential consumers reached historically high levels, distributed generation (DG) was strongly boosted by an interpretation of the existing legal framework that allowed the sharing and selling, through a net-metering tariff, of energy produced by small solar farms within distribution networks. In this context, the DG challenged the status quo and the current market design by selling DG-energy credits within the regulated market, wherein commercialization was only allowed for the distribution company (a regulated monopolist retailer that competes in the wholesale market). So, this was a clear example of a new technology challenging the existing market design and regulation, which failed to properly adapt and internalize the new paradigm. As a consequence, the prevailing market design lost its capacity for self-regulation, as neither wholesale nor retail prices were reorganized to reflect the new technologies, and the variability and spatial distribution of generation and consumption resources that now shape short-term system operations.

It is in this environment, where short-term prices no longer represent the system's operational reality, that competition ceases to operate in the interest of the system and consumers and instead becomes a

competition for the next subsidy. It is also in this environment that economic and regulatory chaos takes hold, and lobbying power replaces market intelligence as the most effective strategy for winning the game. This is the state of Brazil's electricity market at the end of 2025.

After the major electricity rationing crisis of 2001 in Brazil, the Revitalization Committee studied the main causes that led to the collapse and, based on solid technical analysis, laid the foundations for a new regulatory framework. At the heart of this new regulatory system were three main guidelines designed to secure clear long-term price signals to foster investment in new capacity in pace with the rapid demand growth experienced in developing economies:

1. The first guideline stated that 100% of the load must be contracted. An ex-post penalty for under-contracting, together with a limit on cost pass-through for distribution companies, ensured incentives for timely contracting.
2. The second guideline required that every contract be backed by an energy-reliability index, called the physical guarantee; an administratively calculated stamp, representing a probabilistic version of the firm energy certificates used for hydroelectric units.
3. Finally, the third guideline limited distribution companies to purchasing standardized long-term contracts exclusively through public auctions, which, unlike in other Latin American countries such as Chile, were centrally organized by the Ministry of Mines and Energy as single-buyer procurement auctions.

While the first two guidelines ensured that there would be sufficient physical capacity to supply all consumption, the third secured a transparent and competitive systematic contracting scheme to distribution companies, which have the right to pass through on to consumers their purchase costs. Upon its implementation in 2004, the new regulatory design reconnected the load growth with the long-term investment signal, determined by equilibrium in the forward contract market. The result was a new cycle of robust and coordinated expansion that was followed by many countries in Latin America and seen as an interesting case all around the world.

Since 2004, many relevant aspects of power system operations in Latin America (LATAM) have changed, and most of the premises that formerly supported the selected approximations and market design are no longer valid. As a result, the current regulatory framework across LATAM faces numerous challenges. However, following the same logic that supported the 2000s reforms, the current challenges require a careful examination of their causes rather than a focus on their effects and consequences.

In this regard, for a long time, LATAM countries have downplayed the role of short-term spot prices due to the relative abundance of hydroelectric resources and their ability to "resolve" most short-term operational scarcities through their significant ramping capacity and inertia, attributes that confer high flexibility to these units. Now, with the massive integration of intermittent renewable resources, the lessons learned from countries that have been dealing with these issues for more than a decade become extremely valuable.

Thus, the structural solution to the current challenges faced in Brazil regarding the lack of flexibility is far more closely associated with (1) a gradual yet swift reduction of subsidies, (2) aligning spot prices with real-time system operation, (3) the creation of ancillary services markets, and (4) the development of new risk-management instruments and trading channels than with the proposed capacity auctions — a mechanism known to weaken scarcity pricing and distort investment incentives.

This reform agenda, however, does not stop at wholesale market reform. It also requires deeper integration between distribution system operators and the national system operator, as well as the development of the physical and regulatory foundations within the distribution segment necessary for consumers, aggregators, and distributed generators to participate actively in the market and respond to price signals.

These issues do not exhaust the menu of necessary improvements, but they point toward a more structural, self-regulating path, one that is less dependent on subsidies and market reserves than the one currently being pursued. The idea of paying for capacity solely to ensure that specific controllable sources remain in the game is not only a subsidy used to address the distortions created by another subsidy (for renewables), but

also evidence that the current market design and regulatory framework (the rules of the game) have failed to foster what the system actually needs.

Therefore, the proposed capacity reserve auctions — characterized by (i) source-specific products, thereby reducing competition; (ii) static, single-attribute evaluation frameworks; (iii) the absence of clearing against short-term prices (unlike well-established call-option mechanisms already implemented in this country, these capacity contracts are completely disconnected from physical system conditions); and (iv) administratively defined demand, disconnected from the willingness to pay of those who ultimately bear the costs — do not address the structural problem. Instead, they merely add another layer of subsidies that will ultimately require correction.

Chapter 2

A System Designed for Water

2014–2015

In this chapter

A Problem of Water Management 20
The Energy Crisis of 2015 23
Time to Review the Operation and Expansion of the Power Sector 27

Introduction

In October 2014, major Brazilian reservoirs were close to zero, and storage in the Southeast, where the main reservoirs are, stood at about 25%. The official line until the elections was that there was no crisis. The short-term price had signaled scarcity by sitting at its cap since 2013. Distribution companies can pass these costs on to consumers only through the following year's tariffs. Their cash flow broke down, and they had to be rescued with Treasury funds. I wrote the three articles of this chapter during that crisis and in the year that followed. They describe the system this book is about at the moment its weaknesses became visible.

The system was conceived to exploit water. When the reservoirs are full, hydroelectric plants supply more than 90% of consumption, and thermal plants complement them and help save water in adverse years. Everything therefore depends on how the official computer models plan the use of stored water. In 2012 the system had already given a warning. Storage fell from a record above 70% to a record low of about 30%, although inflows were only slightly below average. I traced part of the problem to four flaws in the models and in the rules that feed them: (1) the models simplified transmission, security constraints, and individual reservoirs; (2) their inflow forecasts for the Northeast had overestimated water for twenty years; (3) regulation neither rewarded accurate plant data nor required systematic audits; and (4) the models assumed that delayed plants and lines would arrive on time. The models thus saw a future always more abundant than reality. With empty reservoirs, hydro plants also need more water for each megawatt-hour, so the worse the situation, the harder the recovery. Brazil had no official, audited scarcity index to decide on rationing, as if the country had no inflation index.

By November 2015 the crisis had exposed the institutions as well. For three years the National Electric System Operator had dispatched thermal plants against the official methodology, on grounds of system security. This extra dispatch cost billions and left hydro plants, thermal plants, consumers, and traders without predictability. It was also increasingly influenced by government bodies such as the Ministry

of Mines and Energy. The official model still aggregated reservoirs, barely represented the transmission network, and forecast streamflows from their own past. Versions with individual reservoirs and detailed transmission had existed for more than a decade. I proposed public stress tests of the models against alternatives, an operator with broad and agile autonomy over its models and accountable to society, and input data audited constantly.

In the same article I raised a second problem, which later chapters follow. Expansion was coming from thermal plants, wind farms, and run-of-river hydro plants, whose reservoirs are so small that they must run all the water that arrives through their turbines. Such a fleet needs thermal plants to generate for longer, with higher costs and more emissions. Reservoirs also "store wind", because they can hold back the water equivalent to a surplus of wind generation. For this reason, wind and solar should expand together with hydro. Forbidding large reservoirs to protect the local environment has global costs that society was not weighing. In the North, the new projects would flood less than 10,000 km², while the Legal Amazon lost on average 14,315 km² a year to deforestation between 2000 and 2013.

Core ideas

1. The Brazilian system was conceived to exploit water, and when its reservoirs are full, hydro plants supply more than 90% of consumption.
2. Because everything depends on how official computer models plan the use of water, the quality of those models decides how safely the system is operated.
3. The models simplified the system without need, overestimated inflows to the Northeast for twenty years, relied on unaudited data, and assumed that delayed plants would arrive on time, so they saw a future better than reality.
4. In 2012, storage fell from above 70% to about 30% in a year of nearly average inflows, a warning given before the crisis.

5 In 2014 the price sat at its cap and the Treasury rescued the distribution companies. Lowering the cap and charging generators for emergency generation solved the immediate problem but created distortions and regulatory uncertainty.

6 Brazil had no official, transparent, and audited scarcity index to decide on rationing, as if it had no inflation index.

7 Thermal dispatch against the official methodology, under growing government influence, cost billions and removed predictability. The remedy is public stress tests, an autonomous and accountable operator, and audited data.

8 Expansion without storage reservoirs means more thermal generation, since reservoirs "store wind", and forbidding them has global costs that must be weighed.

Conclusions

In 2014 and 2015 the visible cause of the crisis was a drought, but its roots lay in the management of water. The models assumed a more abundant future than the one that came, their data went unaudited, and the operator acted outside its own methodology. The design depended on reservoirs, and in November 2015 I already warned that the expansion under way was giving up the inexpensive resource that gave the system security and robustness.

The articles

A Problem of Water Management, published in O Globo on 14 October 2014, argues that the drought exposed a deeper problem in how reservoir water is managed and calls for the autonomy of the system operator, the market operator, and the regulator. *The Energy Crisis of 2015*, in Valor Econômico on 24 February 2015, explains why a system designed for water depends on its planning models, lists four flaws in them and in the rules that feed them, and asks for an official scarcity index. *Time to Review the Operation and Expansion of the Power Sector*, in Valor

Econômico on 27 November 2015, turns to the institutions that govern operation and expansion. It is the first article in the book to defend reservoirs as storage for the variability of wind and solar.

A Problem of Water Management

Original title: *Um problema de gestão da água*
O Globo · 14 October 2014
Published version: oglobo.globo.com

ABSTRACT

With major reservoirs close to zero and storage in the Southeast at about 25%, the official line until the elections was that there was no crisis. I argue that the drought exposed a deeper problem in the way we manage reservoir water. The system runs on software that needlessly simplifies its operating reality. Its technical data are not constantly audited and fall out of date. Delays in new plants have become the rule, yet the programs assume they will arrive on schedule. Operating as if the future will always be better and simpler than reality leaves the system vulnerable even to moderate inflows. With little water stored, thermal plants burning expensive fuels set the short-term price, which has sat at its cap since 2013. Distribution companies can pass these costs on only through the following year's tariffs, so their cash flow broke down and the Treasury had to rescue them. Artificially lowering the price cap and charging generators for emergency generation solve problems of the moment while creating economic distortions and regulatory uncertainty. The sector must bring its planning software closer to reality, give distribution companies the liquidity and flexibility to manage their contracts, and guarantee the autonomy of the system operator, the market operator and the regulator.

The Brazilian power sector is going through a serious energy crisis, with major reservoirs close to zero. It is no coincidence that it is also going through a severe financial crisis, with distribution companies "calling for help" from the Treasury to pay their bills. Until the elections, the official line is that there is no crisis, even though we are going through one of the most severe droughts ever recorded, with storage in the Southeast

(home to the main reservoirs) at around 25%. But beyond the drought, the energy crisis has deeper roots, related to the way we manage the water in our reservoirs.

Today the system is operated with software that needlessly simplifies its operating reality and that is fed with technical data that are not constantly audited and therefore fall out of date. Delaying the start of operation of new plants has become the rule rather than the exception. We feed the programs with the information that plants A, B and C will start operating at the end of this year, but we wait until we get there to correct what everyone already knew: the plants will only start running in 2016.

Operating the system on the assumption that the future will always be better and simpler than reality makes it vulnerable even to inflow conditions that are not particularly severe. So, in a drought, which has been our reality since 2013 and precisely when the system should be ready to run a marathon, it has a heart attack in the first few kilometers and has been surviving on life support.

The economic logic of supply and demand is implicit in the operation of the system and in the pricing of energy. Since little water is stored and there is no prospect of high inflows, we have to use thermal plants that burn extremely expensive fuels. This cost is the basis on which the short-term price of energy is formed, and since 2013 that price has signaled the scarcity of supply by reaching its cap.

Because distribution companies can only pass the cost of short-term purchases on to consumers through tariff increases in the following year, their cash flow was thrown badly out of balance. The shortfall exceeded the companies' own value and required the government to rescue them with an injection of Treasury funds. Artificially lowering the cap on the short-term price and allocating the costs of emergency generation to generators are two examples of measures that solve problems of the moment but create major economic distortions and regulatory uncertainty.

This crisis exposes the fragility of the way the power sector's regulatory framework has been implemented. Bringing the software that plans the operation closer to the operating reality, and creating

regulatory mechanisms that give distribution companies the liquidity and flexibility to manage their contracts, are the great challenges the sector must overcome now to restore its stability and attract new investment. In this process, it is essential to guarantee the autonomy of bodies such as the National Electric System Operator (ONS), the Electric Energy Trading Chamber (CCEE) and the Brazilian Electricity Regulatory Agency (ANEEL).

The Energy Crisis of 2015

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Valor Econômico · 24 February 2015
Published version: lamps.ind.puc-rio.br

ABSTRACT

The power crisis of 2015 is real and has already caused an unprecedented shortfall of billions. I trace the energy and financial crises to facts that seem harmless in isolation but together create an unstable regulatory environment with dangerous incentives. Our system was conceived to exploit water, and hydro plants supply more than 90% of consumption when reservoirs are full. Everything depends on how the operator's models plan the use of water. In 2012, storage fell from a record above 70% to a record low of about 30%, with inflows only slightly below average. I point to four flaws: the models grossly simplify transmission, security and reservoir constraints; their inflow forecast for the Northeast has overestimated water for twenty years, and the same holds for biomass, small hydro and wind; regulation neither rewards accurate plant data nor requires systematic audits; and the models assume that delayed plants and lines will arrive on time. They therefore see a future always more abundant than reality, and recovery grows harder as hydro plants lose efficiency with empty reservoirs. Consultants put the chance of rationing above 50%, yet the government bets on a reversal. Brazil has no official, audited scarcity index, as if it had no inflation index.

We are living through a serious crisis in the power sector. Whether you like it or not, whether the government likes it or not, the crisis exists, it is real, and it has already caused an unprecedented shortfall running into the billions, which leads us to two questions: how do we get through the short-term energy crisis, and how do we correct the latent factors that produced both the energy crisis and the financial

crisis? The causes of both crises are rooted in a set of facts that seem harmless in isolation but that, together, create an unstable regulatory environment with dangerous incentives, which do real damage to the economy and to society.

Our power system was conceived to take advantage of the vast water resources we have. When the reservoirs are full, hydroelectric plants supply more than 90% of consumption. However, because river flows and rainfall are uncertain, we need thermal plants to complement the operation and to help save water in times of adverse hydrology. But these thermal plants account for less than 30% of consumption.

Brazil depends essentially on managing the stocks of water in its reservoirs to meet electricity consumption. To get through the alternation between wet and dry seasons safely, the computer models used by the National Electric System Operator (ONS) must faithfully represent the electrical and hydro systems, so as to simulate what may happen in each possible hydrological scenario over the year.

In 2012, the power system had already given a second warning, after the one in 2010, that something was wrong in the way the reservoirs were being operated. The 2012 case is emblematic, because we began the year with the highest storage on record (above 70%) and ended it with another record, the opposite one, the lowest storage on record (about 30%). What is intriguing is that inflows that year were not severely dry, only slightly below average. So we ask ourselves: what led to this emptying of the reservoirs in 2012?

Part of the answer lies in the way we plan the use of reservoir water to produce electricity. The operation-planning models currently used by the ONS struggle to approximate the operating reality satisfactorily. As a result, planning becomes myopic and operation structurally risky.

We can summarize four points of improvement for these models that ought to be examined. The first two are technical and computational:

1. many real operating constraints of the power system, such as transmission and security constraints and the individual constraints of each reservoir and of the hydro cascade, are extremely simplified in the computer model that plans the use of water;

2. the inflow forecasting model for the Northeast region systematically overestimates (and has done so for 20 years) the amount of water that reaches that region, and the same happens with the energy generated by biomass plants, small hydro plants and wind farms.

The last two are technical and regulatory:

3. regulation does not use efficient incentive mechanisms to make companies report the most accurate technical data on their plants and, unfortunately, it does not require the ONS to carry out systematic audits of many of the relevant data to keep the models faithful to reality; and
4. finally, the systematic delays in the expansion schedule, and the failure to account for them in the models, mean that the models do not save water, since they imagine a future in which the commissioning dates of new plants and transmission lines will always be met.

In the current context, the models always indicate water stocks that are more optimistic than they should be, imagining a future that is always more abundant and simpler than reality. Another relevant and seldom discussed point is the low production efficiency of hydro plants when they operate with empty reservoirs. In that situation, a larger volume of water is needed, compared with what normal storage levels would require, to produce the same megawatt-hour of energy. In other words, the worse the situation, the harder and more expensive the recovery becomes.

Since July 2014 we have had technical indications for adopting some kind of preventive mechanism to reduce consumption. But the government denies any such possibility, betting on a reversal even as we live through a scenario never seen before. Today, unfortunately, we are heading toward a situation in which the chance of having to ration already exceeds the incredible psychological mark of 50%, according to figures recently released by specialist consultants who, naturally, use assumptions and data different from the official ones in their analyses.

When we do not know something, the default is to be more cautious than usual. Does the fact that we are dealing with a severe drought,

confirmed since 2014, give us the prerogative to bet on a reversal, or does it impose on us the duty to prepare for the worst? Imagine you are the breadwinner of a family and you lose your job. After a year of spending your savings without finding a new one, would you keep going out to dinner and keeping up your old standard of living, as if nothing were happening?

Several states are already rationing water. The main reservoirs of the Southeast are already brushing against the critical safety limit of 10%. Important reservoirs, such as Ilha Solteira, have dropped below that limit, and their plants have been shut down. The big problem now is that there is no sign announcing the end of the line. There is no official, transparent, reproducible and audited methodology to calculate an energy scarcity index that indicates whether or not rationing is needed.

It is as if we had no inflation index and could make our demands and press those in government only with our own perceptions. Ultimately, this creates an enormous distance between market agents and the government, bringing more uncertainty to a sector that depends on its attractiveness to sustain itself.

Time to Review the Operation and Expansion of the Power Sector

Original title: *Hora de rever a operação e expansão do setor elétrico*
Valor Econômico · 27 November 2015
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ABSTRACT

The energy crisis forces us to reassess the government's actions and the institutions that govern the power sector's operation and expansion. The first problem is operation. For three years, the National Electric System Operator has constantly dispatched thermal plants against the official methodology, citing system security. This extra dispatch has cost billions and left hydro plants, thermal plants, consumers and traders without predictability. Government bodies such as the Ministry of Mines and Energy increasingly influence these decisions. The official model aggregates reservoirs, barely represents transmission and forecasts streamflows from their past alone, although individualized versions have existed for more than a decade. I propose public stress tests against alternative models, an operator with agile autonomy over its models and accountable to society, and constantly audited data. The second problem is expansion. New thermal plants, wind farms and hydro plants with tiny reservoirs mean more thermal generation, higher costs and more CO_2 emissions. Forbidding large reservoirs to protect the local environment imposes global costs. In the North, the new projects would flood less than 10,000 km², while the Legal Amazon lost an average of 14,315 km² a year to deforestation from 2000 to 2013. Reservoirs also store wind, so wind and solar must expand together with hydro.

The energy crisis the country faces forces us to reassess the government's actions and the role of the bodies that govern the operation and expansion of the power sector.

We have an official methodology, programmed in the form of computer models, to determine how thermal plants should generate in order to protect the reservoirs and minimize the total cost of operation. Over the last three years, however, the National Electric System Operator (ONS) has constantly dispatched them, contrary to this methodology, on the grounds of maintaining system security. Yet this extra dispatch is not free. It has been producing costs in the billions and several side effects for the sector's agents, the economy and society.

The wide gap between the actions recommended by the models and what the ONS actually does makes it extremely vulnerable and creates an environment of regulatory instability. Hydro plants no longer know when they will return to generating and stop buying energy in the short-term market. Thermal plants, which have already reached their limit of operating hours, do not know when they will carry out maintenance. Consumers pay prices that do not reflect the operation, with distorted charges, and traders are left with no room to create good business.

Using models has several advantages. They allow us to simulate the impact of measures or adverse situations before they are actually implemented or occur. In this way, they provide transparency and predictability to market agents. Last but not least, they make it possible to accumulate knowledge, with improvements based on past errors and surprises. But for this advantage to leave the conceptual realm, we must invest heavily in continuous feedback between the model and its improvement.

Well into the 21st century, and even with massive parallel cloud computing power already available, we use an aggregate reservoir model that barely represents the transmission network, when versions of this methodology that model each reservoir individually and represent transmission constraints in detail have existed on the market for more than a decade. Moreover, in the age of Big Data, we still use a streamflow forecasting model that looks only at its own past and disregards the climate information available.

I argue for a reform in the management of these models and methodologies. The models should be put to the test, publicly, through

stress tests and comparisons with alternative models. In this scenario, the ONS, which is responsible for the operation, should have broad and agile autonomy over improvements to the models and be accountable to society for its decisions. Input data should be audited constantly, to put pressure on all parties involved to improve the quality of information. This would bring a large gain in robustness, accuracy and reliability to the models, properties that are indispensable for a real and sincere rapprochement between the models and the operation carried out by the ONS.

Moreover, these dispatches "outside" the methodology have been increasingly influenced by government-linked bodies, such as the Ministry of Mines and Energy (MME). These bodies should not interfere with the remit of the ONS, which must operate the system independently of short-term political interests.

The second problem is the expansion of the generation fleet. With expansion coming from thermal plants, wind farms and hydroelectric plants (with reservoirs so small that they must run all the water that arrives through their turbines), we will need thermal plants generating for longer. They make up for the work that used to be done by larger reservoirs, which regulate inflows and transfer water from wet seasons to dry seasons. The consequence of this expansion policy is a higher operating cost and a significant increase in CO_2 emissions.

The alternative is known but has been ignored: resuming the studies that consider larger reservoirs. Society and the responsible agencies are not weighing the fact that forbidding large reservoirs, in order to mitigate the local environmental impact of flooding, produces a global impact on the environment, on tariffs, on energy security and on society. Obviously, we should not go out and build every possible reservoir, but rather reassess the way we measure their positive and negative impacts.

If we look at the North region, for example, the area that would have to be flooded to fully exploit the reservoirs of the new projects is less than 10,000 km² (about 0.15% of the area of the Amazon rainforest), whereas the average area deforested in the Legal Amazon (from 2000 to 2013), according to data from the National Institute for Space Research (Inpe), was 14,315 km² per year.

In addition, alternative sources such as wind and solar, although beneficial to the system, cannot replace hydroelectric plants with reservoirs, because it is the hydro plants that produce in the absence of wind or solar radiation. Hydro reservoirs also play the role of a technology for "storing wind", holding back the water that is energy-equivalent to the surplus of wind generation. The expansion of alternative sources must therefore go hand in hand with the expansion of hydro. Otherwise, more thermal plants will be dispatched to compensate for the inherent variability of alternative renewable sources.

Finally, the combination of a non-transparent operation, carried out under government interference and in a way incompatible with what the official methodology proposes, with an expansion that does not see the multiple benefits of reservoirs (the main inexpensive resource still available that brings security and robustness to the system) reveals a structural and governance problem in the power sector. We need to bring the operating methodology closer to the operating reality, strengthen the role of the institutions, and, within the process of expanding the generation fleet, take into account the global positive and negative impacts that each source has on system operation and on the environment.

Chapter 3

The Lost Coherence: Models, Institutions and the Repeated Crisis

2016–2021

In this chapter

The Welcome Review of the Method for Calculating Electricity Prices 36
Metrics for Evaluation and Monitoring 40
The Electricity Market and Institutional Restructuring 43
The Inconsistency of the Power Sector and the Repeated Crisis 47

Introduction

Coherence between how the operation is planned and how it actually happens is the quality the Brazilian power sector forgot. Its absence breeds inefficiency, litigation, and corruption, and it reduces the sector's attractiveness to private capital. In 2016, after the crisis of the previous years, the government committee that monitors the power sector signaled a review of the methods used to dispatch plants and form prices. I welcomed the review on the condition that it restore this lost coherence. I wrote the four articles collected here between 2016 and 2021, and they approach coherence from four sides: the models, the measurement of their results, the institutions that run them, and the crisis their inconsistency produced again in 2021.

The models matter because the whole design depends on them. The operation model shapes the spot price, at which the market settles what each agent generated or consumed above or below its contracts. It also shapes the physical guarantees and the parameters that decide how technologies compete in auctions for new generation. Physical guarantees are the certificates of firm energy that back every contract. When the long-term planning model ignores transmission, individual reservoirs, the nonlinear efficiency of hydro plants, and the security criteria actually applied, it builds an optimistic view of the future. The water stock is then unprepared for stress, and the short-term model spends most of its time being caught off guard by reality. Much of the volatility of the spot price comes from this process. For this reason I argued that the representation of the future must be fixed before anyone calibrates the risk-aversion parameters, or we end up calibrating aversion to an imaginary risk. In 2019 I added a practical step. Planned and realized operation should be compared through published metrics, just as the country tracks inflation indices, because no one could tell whether deviations came from wrong streamflow forecasts or from an oversimplified model.

The institutions explain why coherence was so hard to recover. The system operator and the market operator had to use models from a single provider, the Electric Energy Research Center of Eletrobras, which did

not answer to the system operator. The operator could not choose its own tools. The planner worked apart from the operator, although the operator has the information the planner needs and planning exists to serve the operation. With responsibility spread across several bodies, no one is fully responsible for anything, and the bill goes to the consumer. The centralized model based on audited costs had served the 1990s well, and since the end of the rationing in the early 2000s a bid-based market has been increasingly seen as the way forward. Public Consultation No. 33, of 2017, put this discussion on the table. Getting there requires qualified people, institutions organized so that incentives for self-adjustment work, and a realistic timetable.

The crisis returned in 2021, and on 27 May the government committee met in an extraordinary session. Reservoirs in the Southeast stood at about 32% at the start of the dry season, after one of the worst wet seasons on record, and the spot price still hovered around a median of R$250/MWh. The cause was the one I had described in 2016. The water value measures how much the future cost of supply falls when water is kept in storage. In 2021 it came from a long-term model that ignored the network, individual reservoirs, and more than fifteen years of evidence of falling inflows. Its optimistic bias passed into operating decisions and into current prices, while the short-term scheduling model saw every constraint the long-term one ignored. The result is a sequence the sector has known since 2013. Thermal plants are dispatched too late, reservoirs are depleted early, and prices stay artificially low. Then the operator, distrusting its models, dispatches plants outside the merit order, and prices hit the regulatory cap when nothing more can be done.

Core ideas

1. Coherence between operation planning and reality is the quality the sector forgot, and its absence breeds inefficiency, litigation, and corruption.
2. The operation model is the cornerstone of the Brazilian design, because it shapes the spot price, the physical guarantees, and the parameters of the auctions for new generation.

3 Inconsistency between planned and actual operation explains much of the volatility of the spot price.

4 Before calibrating risk aversion, the representation of the future inside the model must be fixed, or the sector calibrates aversion to an imaginary risk.

5 Planned and realized operation should be compared through published, independent metrics, such as a record of out-of-merit-order dispatch and the errors of forecasts from 1 to 48 months ahead.

6 The institutional structure leaves no one accountable for results, with one provider of models that does not answer to the operator, an operator that cannot choose its models, and a planner apart from the operator.

7 The centralized, cost-based model served the 1990s, and a bid-based market requires qualified people, reorganized institutions, and a realistic timetable.

8 The 2021 crisis repeated those since 2013, and the remedy is to give the operator freedom to choose its models and hold it accountable for the adherence between planned and realized operation.

Conclusions

Between 2016 and 2021 the diagnosis did not change, and neither did the outcome. The models that plan the use of water and form prices kept building an optimistic view of the future, and the institutional structure left no one accountable for the gap. The remedy I proposed follows two basic principles of corporate management: give freedom and demand results.

The articles

The Welcome Review of the Method for Calculating Electricity Prices, in Valor Econômico on 1 September 2016, states the principle of

coherence and explains why the operation model is the cornerstone of the design. *Metrics for Evaluation and Monitoring*, in CanalEnergia on 15 January 2019, proposes published indicators of the adherence between planned and realized operation. *The Electricity Market and Institutional Restructuring*, in Valor Econômico on 31 January 2019, at the start of a new government, analyzes the institutional obstacles to a bid-based market. *The Inconsistency of the Power Sector and the Repeated Crisis*, in Valor Econômico on 16 June 2021, shows the same mechanism at work in that year's water crisis and asks for an operator free to choose its software and accountable for its results.

The Welcome Review of the Method for Calculating Electricity Prices

Original title: *A bem-vinda revisão do método de cálculo da energia elétrica*
Valor Econômico · 1 September 2016
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ABSTRACT

Coherence between operation planning and reality is the quality the power sector forgot, and its absence breeds inefficiency, litigation and corruption. The Power Sector Monitoring Committee has signaled a review of the dispatch and price-formation methodologies. I welcome it, provided it rethinks who is responsible for the models and introduces data auditing. The Electric Energy Research Center, an Eletrobras entity independent of the system operator, is the sole provider of the models that the system and market operators must use. Options range from open-source models to a full reorganization of institutions and responsibilities. A working group of market agents, universities and government should test them within about a year. Our studies show that inconsistency between planned and actual operation imposes a large extra cost. It explains much of the volatility of the short-term price. The long-term model ignores transmission, individual reservoirs, nonlinear hydro efficiency and the security criterion. It therefore sees an optimistic future, and the short-term model keeps being caught off guard by reality. The operation model is the cornerstone of the design, from the price to physical guarantees and auction parameters. Before calibrating risk aversion, we must fix how the model computes the future, or we will calibrate aversion to an imaginary risk.

The main quality forgotten in the power sector in recent years, and whose absence produced a large part of the problems we have accumulated today, is coherence. The lack of coherence brings several

side effects well known in the sector: inefficiency, litigation and corruption. These effects, which reduce the sector's attractiveness to private capital and its long-term sustainability, can be mitigated by seeking the lost coherence between operation planning and reality.

In the latest minutes of the Power Sector Monitoring Committee (CMSE), the government pointed to the need to review the dispatch and price-formation methodologies, so as to bring more transparency and efficiency to the electricity market. The review signaled by the government is welcome and, if done well, will benefit the market. But the subject is complex and should involve a broad technical discussion.

We need to restore coherence and introduce regulatory robustness into the methodologies. For this review not to be just one more regulatory change, of the kind that only adds noise to every agent's planning and thereby creates more incoherence, we must rethink the institutional structure of those responsible for the models and introduce some process of data control and auditing.

But we cannot fall into the error of bureaucracy and inefficient centralized control. We need to find a design that leads each agent individually, from generation to the consumer, from the system operator to the market operator, toward efficiency and consistency. Agents must be given incentives to invest in technology to measure and forecast their own data better. The operator must be induced to select the best model and to be consistent with it.

Today we are anchored in an old regulatory design, slow-moving and not conducive to efficiency and coherence, in which Cepel (the Electric Energy Research Center), an entity linked to the Eletrobras group and independent of the ONS (the National Electric System Operator), is the sole provider and maintainer of the chain of models that both the system operator and the market operator must use.

Many designs can be conceived, from an "open source" design (in which the models' code is open and receives periodic contributions) to a complete hierarchical reorganization of institutions and responsibilities. This review must therefore be broad and must involve market agents, universities (in Brazil and abroad; yes, we have much to learn from foreign researchers) and the government. We need to set up a working

group to test the ideas and their impacts through simulation studies of the whole chain. We need to find the institutional structure that induces coherence. And this is not a job for four months, but it cannot take much more than a year either.

Our latest studies on the impact of the inconsistency between planned and actual operation, caused by simplifications in the models, show results that confirm the high relevance of this issue and its large impact in terms of extra cost. A large share of the problems we know today is amplified by this kind of inconsistency and by inaccuracies in input data.

For example, much of the volatility of the PLD (the settlement price for differences, which is the short-term, or spot, price of energy), which so haunts the sector's agents, can be explained by this process. When we plan the water stock with a simplified model of the system, one that, for example, ignores transmission constraints, the individual constraints of the reservoirs and the nonlinear efficiency of hydro plants, and disregards the security criterion and the allocation of reserves that are actually applied, we create inside the model a view of the future that is, in general, optimistic. As a result, the water stock will always be unprepared for stress situations. Consequently, the system becomes gradually more vulnerable, and the short-term model spends most of its time being caught off guard by the reality that the long-term model failed to perceive.

The operation model's surprise translates into the high PLD spikes that signal resource scarcity. But we can add to the set of sources of inconsistency the classic unmodeled uncertainties, such as the variability of load and of fuel costs, and inaccuracies in input data, such as the commissioning schedule. These produce very similar effects because, once again, planned operation drifts away from actual operation.

In our current sector design, the operation model is the cornerstone, influencing everything from the PLD to the calculation of physical guarantees (firm-energy certificates) and the parameters that define the competitiveness of different technologies in the auctions for new generation projects. The operation model therefore influences, directly or indirectly, the entire chain of the power sector, including the

sector's very attractiveness to private capital. So, before calibrating the risk-aversion parameters of the current computer model, we must review how we are computing the future inside it, so as not to fall into the trap of calibrating parameters of aversion to an imaginary risk, which is not the one we will face.

Bringing the models closer to reality raises the transparency and credibility of the sector's institutions, minimizing lawsuits and increasing the predictability of energy prices in the short and long term. Greater price predictability, in turn, benefits all agents and investors who do their homework and repels those who seek gains only by anticipating the palliative regulatory measures that the Brazilian Electricity Regulatory Agency (ANEEL), the Electric Energy Trading Chamber (CCEE) and the ONS are forced to take to correct the distortions created by the lack of coherence.

Metrics for Evaluation and Monitoring

Today we do not know whether we are deviating from the plan because our streamflow forecasts are badly wrong or because we oversimplify the modeling of the power system; everything is mixed together and unmeasured

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ABSTRACT

In Brazil, much effort goes into making the operation planning model converge and run fast. Not even a fraction goes into evaluating the operating policies the model produces in practice. Without indicators, society lacks references for the necessary debates. Today we cannot tell whether operation deviates from the plan because streamflow forecasts are wrong or because the models oversimplify the system. A published record of out-of-merit-order dispatch would show how far the operator distrusts the models. Such numbers lie scattered in sector reports, and no impartial institution publishes them. Forecast errors of streamflows, load and small renewable plants over the planning horizon go untracked. Consistency between plan and reality matters most in a hydrothermal system, where planning weighs the benefit of storing water against the cost of not using it today. Errors in this trade-off can cost society dearly. I propose metrics of adherence between planned and implemented operation to let the National Electric System Operator test its performance. If forecasts for 1 to 48 months ahead fail beyond statistical margins, planning sends wrong opportunity-cost signals to the short-term models. The cheapest resources are then used inefficiently and depleted. Regularly published sector indices, like inflation indices, would help agents today and support the transition to a bid-based market.

In the Brazilian power sector, much effort has historically been devoted (rightly) to making the computational model for long- and medium-term operation planning converge stably and to ensuring adequate computational performance with cut-selection methods, and so on. Yet we do not spend even a fraction of that energy on creating methodologies to evaluate and control the quality of the operating policies derived from these models when they are implemented in practice. With no such control, and no indicators that allow a minimum consensus on the adequacy of a given operating policy, society is left without parameters and references for the necessary discussions and changes.

Today we do not know whether we are deviating from the plan because our streamflow forecasts are badly wrong or because we oversimplify the modeling of the power system; everything is mixed together and unmeasured. A historical record, built with a clearly and transparently published methodology, of the frequency, quantity and cost of the energy dispatched out of merit order for energy-security reasons could indicate the degree to which the operator distrusts the models. However, this is just one example of numbers that exist scattered across sector reports but are not organized and published in a systematic way by an impartial institution. We do not track the forecast errors of streamflows, load and renewable injection (small plants) over the medium- and long-term horizon used in planning. Getting it right on average one month ahead is not enough; it is important for forecasts to be consistent over the medium and long term.

Consistency between planning and operational reality is a highly relevant signal, especially in a hydrothermal system, where water is a scarce resource to be managed over time. Thus, the planning stage is important because it decides the optimal use of this resource by weighing the economic benefit of storing it for the future against the cost of not using it today. Recent studies by researchers at the Laboratory of Applied Mathematical Programming and Statistics (LAMPS) of the Pontifical Catholic University of Rio de Janeiro (PUC-Rio) show that getting this calculation wrong can impose an enormous cost on society, with many repercussions. A methodology for tracking planning versus

reality would therefore be an innovative initiative, fully aligned with the idea behind multistage models and with the importance of their being time-consistent.

Creating and using metrics to track the adherence between planned operation and the operation actually implemented would be a first and major step toward allowing the National Electric System Operator (ONS) to test its performance and improve the coherence between its models and its operational actions. If the forecasts made by the planning models for horizons of 1 to 48 months ahead are not borne out in practice, within statistical margins, then we are bringing wrong opportunity-cost signals from planning into the short-term models. The consequence of this mismatch is well known: a systematically inefficient use and depletion of the system's cheapest resources.

Today we have a few scattered initiatives, with methodologies that are not very transparent and not published. Just as we track inflation indices, the trade balance and so on, we could have a range of sector indices published regularly, with broad technical discussion of the calculation methodologies, transparency and impartiality. Such metrics would bring large gains to agents even under the current sector model, in which operation is decided centrally, and they would be an important step in the transition to a bid-based market model.

The Electricity Market and Institutional Restructuring

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Valor Econômico · 31 January 2019
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ABSTRACT

Brazil's power sector runs on centralized coordination of energy resources by the National Electric System Operator, based on audited costs. It served the 1990s well, when we were discovering the benefits of integrated hydro management. Since the rationing of the early 2000s, a bid-based market has increasingly been recognized as the pro-efficiency answer to its exhaustion. Crisis after crisis, the centralized model has failed to react in time to climatic, physical, economic and political adversity. Even the 2004 reform did little to create incentives for efficiency and accountability for data. I argue that a major obstacle is institutional. The sector lacks qualified people, academia keeps outdated curricula, and companies invest little in it. Sector and government bodies are held back by old vices, bureaucracy and institutional protectionism. First, the operator and the planner work apart, although the operator holds what the planner needs. Second, the operator cannot choose its models, a monopoly of the research arm of Eletrobras. With responsibility diluted, no one answers for anything, and the bill goes to the consumer. The 2017 public consultation on modernizing the sector put these issues on the table. The new government opens a window, provided we train people, organize institutions around self-adjusting incentives and adopt a realistic four-year timetable.

The operating model currently in force in the Brazilian power sector rests on the centralized coordination of energy resources by the National Electric System Operator (ONS), based on audited costs. This model

played a fundamental role in the 1990s, when we were discovering the benefits of the integrated management of water resources in a system with a wide diversity and complementarity of hydrological regimes. However, since the end of the rationing, in the early 2000s, the implementation of a bid-based market has been increasingly recognized as the pro-efficiency solution to the exhaustion of the current sector model.

The current model, in which all data and views of the future are managed centrally, has proven, crisis after crisis, unable to react in time to climatic, physical, economic and political adversity. Even after the broad regulatory reform carried out in 2004, the absence of incentives for operational efficiency and the lack of coherence in holding agents accountable for their actions and for the accuracy of the technical data they report remained largely unchanged. And despite countless demonstrations that the centralized model is exhausted, and the growing call for a model more consistent with market incentives, little progress has been made in the technical debate on this transition.

There is no objective, technical discussion in the sector about practical proposals for a bid-based market that takes into account the peculiarities of the Brazilian power sector. And, contrary to what is often said, international experience can help us a great deal. The absence of a critical mass of truly qualified people to take up and address these discussions is a major gap. Yet academia has not been preparing people for this discussion and keeps curricula that are outdated for this new reality, in which concepts from economics and engineering are inseparably intertwined. Nor do companies make large investments in academia to raise the technical level of the sector, unlike in developed countries, where the industry–academia partnership has already proven to be the main foundation for the transition between models. The sector's institutions and government bodies, for their part, are mostly taken over by old vices and outdated views that block the most obvious and necessary updates to their staff and structure, usually because of bureaucracy and institutional protectionism.

Notwithstanding, one of the greatest obstacles to this discussion taking place, and to the status quo being questioned through the sector's

own internal mechanisms, lies in the current hierarchical structure of the sector's institutions. Over time, the current structure was organized precisely to prevent broad discussion. Moreover, a second consequence of this protectionist organizational structure is institutional isolation and a great loss of efficiency in the interaction between bodies that should be working in close cooperation.

Some interesting examples of major inefficiencies are easy to identify. The first lies in the complete separation between the ONS (the National Electric System Operator), responsible for operating the power system efficiently, and the planner, responsible for designing the system so that the former can play its role in the best possible way. Regardless of how these two agents carry out their tasks, whether using the results of a market or in a fully centralized way, the general principle evident in the definition of these two bodies already tells us that they should walk together. After all, the operator has the information the planner needs, and the planner plans for the operator's benefit. Yet today we have a complete separation between the two agents, resulting in disconnected data and criteria and in a lack of coordination between expansion and operation.

A second example stems from the operator's lack of freedom to choose its own computer models for operation. Against international experience and common sense, the supply of the computer models that the operator must use to optimize the use of energy resources is a monopoly of Cepel (the Electric Energy Research Center), the research arm of Eletrobras, which does not answer to the ONS.

Besides creating the inefficiencies typical of any market reserve, this restriction prevents any effective policy of holding the ONS accountable, or rewarding it, for efficiency and coherence in the use of energy resources. In this scenario, where responsibility for inefficiencies is spread across several institutions, no one is 100% responsible for anything. We know the result well: many profit for the wrong reasons, the bill goes to the consumer, and the beneficiaries fight to keep the status quo.

Implementing a market brings with it the possibility of a systemic gain of great proportions, through the reorganization of institutions and

the realignment of their roles and incentives. Public Consultation No. 33 (CP 33), the 2017 consultation on the modernization of the rules of the Brazilian power sector, put this and many other important discussions on the table. We now have a unique window of opportunity, at the start of this government, to begin the changes. But we need a program that recognizes the complexity of this agenda and does not arrive with ready-made formulas, because prior technical debate and the analysis of international experience are of vital importance.

Finally, we must prepare people for a solid transition, organize the institutions so that the incentives for self-adjustment are effective, and create a realistic timetable for the next four years.

The Inconsistency of the Power Sector and the Repeated Crisis

The spot price (PLD), which takes the system's operation under adverse conditions into account, does not capture an imminent risk that everyone perceives

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ABSTRACT

On 27 May 2021, the Power Sector Monitoring Committee held an extraordinary meeting on a new water crisis. Southeast reservoirs stood at about 32% of capacity at the start of the dry season, after one of the worst wet seasons on record. Yet the spot price, computed with models that simulate adverse conditions, hovered around a median of R$250/MWh. Fortunately, the most concrete problem is not hard to identify. The operator must compute the water value with the official long-term planning model. That model ignores the transmission network, the constraints of individual reservoirs and more than 15 years of evidence of falling inflows. Its optimistic bias passes into operating decisions and today's prices. The short-term scheduling model sees every constraint the long-term model ignores. This inconsistency produces a familiar sequence: thermal plants dispatched too late, reservoirs depleted early, artificially low prices before the crisis, out-of-merit-order dispatch by an operator that distrusts the models, and prices at the regulatory cap once nothing can be done. The same effects have produced the crises since 2013. My proposal follows two basic principles of corporate management. The operator should be free to choose the software it finds most efficient. It should also answer for the adherence between planned and realized operation.

On 27 May 2021, the Power Sector Monitoring Committee (CMSE) held an extraordinary meeting to assess the country's new water crisis. The diagnosis was what everyone already knew: reservoirs in the Southeast at very low levels for the start of the dry season (about 32% of their maximum capacity), one of the worst inflows on record from September 2020 to May 2021 (the wet season, when reservoirs fill up to face the dry season), and the need to relax constraints and coordinate the multiple uses of water so that we can get through the dry season without rationing.

Meanwhile, the spot price (PLD, the settlement price for differences), which should signal to market agents the energy scarcity for the coming dry season that the current situation already makes clear, remains lenient toward what everyone has already perceived, hovering around a median value of R$250/MWh until 29 May.

But why do we live from scare to scare in this sector? And why does the PLD, which is calculated with sophisticated models that simulate the operation of the system under adverse conditions, fail to capture the imminent risk that everyone can perceive? Why do we systematically have to intervene manually with out-of-merit-order actions, incurring exorbitant costs that disrupt the whole economic logic of the market? Is there something fundamentally wrong that drives the sector into crises and disguises them from the signal the PLD should send? The answer is yes!

Without giving in to the temptation to revisit the genesis of the sector's design to argue that the sector should migrate to a market model, known as offer-based dispatch, I choose here to be quite pragmatic and emphatic. This is because this is neither the first nor the second article I have written on the same subject, and because I believe that, before migrating to a market model, we have homework to do. So I begin by saying that, fortunately, our most concrete problem at the moment is not so hard to identify. Most of its roots lie in the planning stage that the National Electric System Operator (ONS) must carry out with the Newave software, whose use is mandatory.

It is with this software, built and maintained by the Electric Energy Research Center (Cepel), Eletrobras's research center, that the ONS

calculates the water value. This indicator is extremely important, because it measures how much the future cost of meeting electricity demand will fall if we keep water stored to use it in the future. The water value is thus the key to deciding how much of the stored water the ONS can use today while ensuring that it will not face crises like these in the future. This indicator is also the component of the PLD that should carry the warning of scarcity in the coming dry season.

With the context set, the problem is that there is an optimistic bias in the calculation of the water value. This bias stems from a series of simplifications of the reality of the power system in the software that calculates it. And this bias is passed on not only to operating decisions but also to today's prices. As a result, the use of water and the pricing of energy, which should be influenced by the future scarcity already mapped within the planning horizon, become myopic about what everyone can already see.

The simplifications introduced in Newave, under the excuse of a computational complexity that was overcome some years ago (mainly through the wide availability of high-performance cloud computing), are so deep that they go as far as ignoring the existence of the electrical network itself. When we calculate in Newave how much the water left for the next dry season is worth, we pretend that there will be no network constraints, that there will be no individual constraints for the many reservoirs, that inflows will be close to their long-term averages (despite strong evidence, for more than 15 years, of a reduction in these values), and so on.

But the problem does not end there. The problem materializes in day-to-day operation. That is, at the moment of operating the real system on the basis of an optimistic water value. At that moment, the ONS compares this value with the cost of thermal plants using a piece of software designed specifically for short-term operation, DESSEM. Because DESSEM must deliver a realistic operating plan for the next day, it needs to see all the system's constraints, the very ones that were disregarded in Newave.

Thus, the consequence of this great inconsistency between the reality considered in calculating the water value and the reality portrayed in

the short-term software is a sequence of events familiar to the power sector: 1) thermal plants not dispatched with the right lead time; 2) early depletion of reservoirs even in low-inflow situations; 3) artificially low short-term prices in the run-up to crises; 4) out-of-merit-order dispatch orders, owing to the operator's and the CMSE's distrust of the models; and finally, 5) short-term prices that hit the regulatory cap when the crisis sets in and there is nothing left to do.

The effects behind this new crisis are more or less the same ones that have produced the crises since 2013, the old inconsistency between planning and real operation. They can be strongly mitigated through simple measures, such as giving the ONS the freedom to choose the software it considers most efficient and holding this entity accountable for the adherence between planned and realized operation.

These are basic principles of corporate management: give freedom and demand results. Until such measures are put into practice, we will keep seeing the sector's institutions "working at cross purposes" to avoid rationing at all costs, some agents profiting unduly in crisis situations and others losing a large part of the capital they invested, even after doing all their homework. Moreover, this simple and almost obvious proposal would bring benefits to other thorny issues in the sector, such as the generation scaling factor (GSF) and physical guarantees (firm-energy certificates).

Chapter 4

Pricing Time: From Hourly Prices to Ancillary Services

2018–2024

In this chapter

Hourly Prices: Opportunities and Challenges 56
The New Components of the Electricity Price in 2021 60
Rethinking Energy Management and the Role of Generation Sources 64

Introduction

Until the end of 2020, the Brazilian spot price was a weekly price. This is the price that settles all differences between contracts, consumption, and generation. Prices that vary across the hours of the day tell generators and consumers when operational flexibility is limited, just as prices that vary across the network tell them where transmission is limited. The intention to create hourly signals dates back to the period after the 2001 rationing, and Public Consultation No. 33, of July 2017, finally set a date for them. When I wrote the first article of this chapter, in February 2018, hourly prices were due to take effect in 2019. By April 2020 the date had moved to January 2021, and hourly prices were implemented that year. In these three articles I follow this change and then argue for the next one, prices for ancillary services and flexibility.

Price formation is the cornerstone of an electricity market, because through it buyers and sellers recognize scarcity and adjust how they consume and produce. Price differences across hours and across the network give value to local generation, storage, and demand response. These signals became more relevant as intermittent renewables grew and as hydroelectric plants lost the ability to absorb every intraday variation at zero cost. Hourly prices also raise questions that are still open. Generators have ramp limits, which constrain how fast they can raise or lower output and couple decisions across hours. When those limits bind, marginal prices can turn negative or rise above the cost of the most expensive plant in operation. Ignoring these signals would distort precisely the incentive to invest in storage and demand response. Prices that account for the uncertainty of renewables and load also require energy and reserves to be co-optimized, that is, scheduled together in a single calculation.

I pointed to two risks in the transition. Agents would have to forecast hourly prices well beyond the few weeks covered by the official scheduling model, since the market operator determines prices but does not forecast them. The official long-term model, in turn, still ignored the short-term constraints that would form the new prices. Its water value, which measures what stored water is worth for the future, had

an optimistic bias. That bias could contaminate the hourly prices from birth, and also the indices that select projects in new-energy auctions. In 2020 I described what the new prices would reveal. Set a day ahead, they would not yet reflect actual costs, but they would come much closer to real operation than weekly prices. Abrupt swings between consecutive hours would bring to light a system cost previously buried in charges. Pricing that cost would attract storage, pay hydro plants correctly, and encourage demand response, without subsidies or market reserves. Negative prices were not yet expected in Brazil for three reasons: the flexibility inherited from a predominantly hydroelectric system, the still unknown effect of the pandemic on demand, and the floor on the spot price.

In 2024, with solar generation at times second only to hydro, I argued for the next step. Two kinds of service must be told apart. Ancillary services are the flexibility to deviate from the scheduled operating point within milliseconds to minutes, covering everything the schedule does not foresee in real time. Flexibility products are offers of additional ramping capability, up or down, for well-defined intervals of the daily schedule. Hydro and thermal plants provide almost all of both in Brazil. Energy, reserves, and ramping should be co-optimized in the daily schedule, with guaranteed deliverability through the network, and the marginal costs of these services should be priced alongside the spot price. Every source that contributes would be paid on an equal footing, and the water value would be updated consistently. Only then will the sector discover which technologies and which mix of sources will prevail.

Core ideas

1. Price formation is the cornerstone of an electricity market, and price differences across hours and across the network reveal where transmission and flexibility are limited.
2. Hourly prices became more urgent as intermittent renewables grew and hydro plants lost the ability to absorb every intraday variation at zero cost.

3 When generators reach their ramp limits, marginal prices can turn negative or exceed the cost of the most expensive plant in operation, and these signals reward storage and demand response.

4 Prices that reflect the uncertainty of renewables and load require energy and reserves to be co-optimized.

5 A long-term model that ignores short-term constraints passes its optimistic water value to the new prices and to the indices of new-energy auctions.

6 The hourly price of 2021, set a day ahead, was expected to reveal opportunity costs that were previously hidden in charges.

7 In 2020 Brazil still lived on flexibility inherited from a predominantly hydroelectric system, and this was one of the reasons negative prices were not yet expected.

8 The next step is to price ancillary services and flexibility products at marginal cost alongside the spot price and to pay every source on an equal footing, so that the mix of sources is discovered.

Conclusions

The move to hourly prices in 2021 brought prices closer to the operation and could bring to light costs previously hidden in charges. It also left the work half done. Prices remained set a day ahead, ancillary services remained without a price, and the long-term model kept passing an optimistic water value to the short term. In the articles of these years I already described the second step. Flexibility and ancillary services must be priced alongside energy.

The articles

Hourly Prices: Opportunities and Challenges, in CanalEnergia on 21 February 2018, sets out the principle of price formation and the open questions of hourly prices, from ramp limits to the optimistic bias of the long-term model. *The New Components of the Electricity Price in 2021*,

in Valor Econômico on 14 April 2020, explains what the hourly price would reveal and why abrupt swings between hours expose real system costs. *Rethinking Energy Management and the Role of Generation Sources*, in Valor Econômico on 23 April 2024, distinguishes ancillary services from flexibility products and presents their pricing as a step as natural and necessary as the hourly prices of 2021.

Hourly Prices: Opportunities and Challenges

The sector's intention to create these hourly signals, widely used in other systems, has long been discussed and dates back to the post-rationing period

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CanalEnergia · 21 February 2018
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ABSTRACT

Price formation is the cornerstone of an electricity market. Price differences across the network and the hours of the day show generators and consumers where transmission and operational flexibility are limited. These differences give value to local generation, storage and demand response. Following Public Consultation No. 33 of July 2017, hourly prices will take effect in 2019. They are the first step toward assessing a bid-based market. Hourly prices grow more relevant as intermittent renewables expand and hydroelectric plants lose their ability to absorb every intraday variation at zero cost. Marginal pricing raises open questions. When generators reach their ramp limits, prices can turn negative and mix the costs of different hours. Ignoring these signals would distort the incentive to invest in storage and demand response. Hourly prices must also reflect the uncertainty of renewables and load, which requires co-optimizing energy and reserves. I see two challenges for the transition. Agents will have to forecast hourly prices beyond the few weeks seen by the scheduling model. The official long-term planning model still ignores short-term constraints, and its optimistic bias in the water value may contaminate the new prices and the indices used in new-energy auctions. The change is welcome and gives academia a prominent new role.

The cornerstone of an electricity market is its price formation process. Through it, buyers and sellers recognize the signals of resource scarcity and feed them back into their consumption and production strategies. It is through price differences at different points of the network and at different hours of the day that generators and consumers understand that there are transmission limits or limits on operational flexibility, and thus come to see value in investments in local self-generation or cogeneration, in storage systems and in demand-response strategies.

The sector's intention to create these hourly signals, widely used in other systems, has long been discussed and dates back to the post-rationing period. It usually comes with a second, far more controversial discussion, that of the bid-based market system. Despite this controversy, hourly prices are a consensus among most specialists. They become increasingly relevant as we raise the share of intermittent renewable sources in the electricity mix and as the ability of hydroelectric plants to absorb any and every intraday variation at zero cost runs out.

Public Consultation No. 33 (CP 33), of July 2017, rekindled the flames of the old discussions through a proactive agenda with long-term goals. As a consequence of this initiative, the hourly price signal will take effect in 2019, with publication starting this year. Many opportunities and challenges will arise from the implementation of this new price system, which represents the first and important step toward analyzing a possible migration to a bid-based market system.

However, the definition of hourly prices already raises, by itself, questions that are still open in the literature of the field, and for which different solutions have been created case by case. There is no consensus on which price formation model best recovers the generators' main fixed costs and other opportunity costs. The classical solution, based on marginalist theory, in which the price is set by the incremental cost of producing the next megawatt, can produce prices that are hard to understand at first sight, with negative values (observed in several countries), and that mix the cost structures of different hours of the day. This happens when the system runs into the generators' ramp-up or ramp-down limits, which couple decisions across different hours of the day. Yet if we ignore these signals, we distort precisely the incentive

to invest in storage plants or demand response that could relieve these constraints.

These challenges are amplified even further in the presence of strong variations in load or in intermittent renewable generation. Just as it is impossible to conceive of prices that ignore inflow uncertainty and the opportunity cost of using water in future months, we cannot conceive of hourly prices that do not incorporate the uncertainty of renewables and load and the opportunity costs of operational constraints in the other hours of the day. This issue is widely discussed in the countries that have already made this transition, which recognize the need to include in the methodology for operation and price setting the co-optimization of energy and generation reserves, the idle and available capacity used as insurance against short-term uncertainty.

A second relevant question is: how will the sector's agents face the move to hourly prices? Two important points must be addressed to ensure a smooth transition. The first is the predictability of hourly prices. Although there is already a methodology for hourly generation scheduling, through the DESSEM software of the Electric Energy Research Center (Cepel), which in principle will give rise to the hourly prices in 2019, agents and academia need to start thinking about their own methodologies for forecasting hourly prices over a horizon longer than the one DESSEM sees, currently a few weeks. This is because it is not the market operator's role to forecast prices, only to determine them. Consumers, generators and traders, however, need to set their long-term contracting, hedging and investment strategies, and for that they will need to forecast prices over this horizon. In this race, the winner will be whoever has the best view of the representation of the physical system and of the uncertainties that affect actual operation.

The second point is a little more subtle: the official long-term planning model, Newave (also maintained by Cepel), does not yet incorporate the short-term constraints that are already applied in practice today and that will also form the price from 2019 onward. These simplifications in long-term models have been studied in scientific work and appear as the cause of a strong optimistic bias, which affects everything from prices to reservoir levels. This effect will be perpetuated if the long- and

short-term models are not made compatible, and it will contaminate all the information in the new hourly prices, which run the risk of being born already drowned by this optimistic bias in the water value. Moreover, much of the methodology that supports generation expansion, such as the calculation of the indices that determine which projects will be bought in new-energy auctions, depends on representing short-term constraints in the planning models.

The move to hourly prices is welcome and brings with it great challenges and opportunities. Hourly pricing will put a spotlight on a series of difficulties we face in the short term. This process will open the door to a more realistic and technical discussion about migrating to a bid-based short-term market, and it will give academia a new role of prominence and responsibility in the dynamics of the sector.

The New Components of the Electricity Price in 2021

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Valor Econômico · 14 April 2020
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ABSTRACT

In January 2021, Brazil's short-term electricity price, which settles all differences between contracts, consumption and generation, will become hourly. The director-general of the National Electric System Operator has said the COVID-19 crisis will not delay it. The model that computes the operator's daily schedule will set the new prices. Set a day ahead, they will not yet reflect actual costs, but they will come much closer to real operation than today's weekly prices. If well calculated, hourly prices will reveal the opportunity costs of scarce resources and attract investment. When generators reach their ramp limits, prices can rise above or fall below the variable cost of the most expensive plant in operation. In thermal-based systems with much wind and solar, negative prices and price spikes are not rare. Brazil will not see negative prices yet, because of the flexibility inherited from a predominantly hydroelectric system, an unknown drop in demand from the COVID-19 crisis and the price floor. I argue that abrupt swings between hours are not necessarily wrong or harmful. They reveal a system cost previously hidden in charges. Pricing it can attract storage, pay hydroelectric plants correctly and encourage demand response. The technologies the system needs will then be attracted economically, without subsidies or market reserves.

According to a recent statement by the director-general of the National Electric System Operator (ONS) at a sector webinar, the current COVID-19 crisis will not delay the change in the short-term electricity price scheduled to take effect in January 2021.

The main practical function of short-term electricity prices is to settle, at the Electric Energy Trading Chamber (CCEE), all the differences between contracts, consumption and generation. That is why they are known as settlement prices for differences (PLD). In less than a year, the computational model that the ONS uses today to compute the daily schedule of generators will also be used to set the new short-term electricity prices on an hourly basis. **If well calculated, the hourly PLD has the potential to reveal to agents the opportunity costs of the system's scarce resources and to create important financial incentives to attract new investment.**

This change will have a profound impact on every agent in the Brazilian power sector. The complexity inherent in the technological, climatic, political and economic features that affect price formation demands close attention from regulators, even in the most efficient and mature markets of the modern economy. It is crucial to understand the features and challenges that this new system imposes in order to create the right monitoring and improvement mechanisms for January 2021, when the hourly PLD is due to take effect.

With the change, the CCEE will calculate the hourly PLD from the marginal costs of the new daily operation carried out by the ONS. These prices will not yet reflect the system's actual costs, since they will be set a day ahead (ex ante), but they will come much closer to real operation than the current weekly prices. We will begin to see in the PLD a new dimension of the system's opportunity costs, until now hidden behind the inefficiencies of a non-optimized operation. And it is these new components that explain how the hourly PLD can differ, upward or downward, from the variable cost of the most expensive plant in operation, a topic that has been bothering many agents and generating much debate in sector forums.

In thermal-based countries with a high integration of intermittent renewable plants, such as wind and solar, negative prices or price spikes are not rare in critical hours, when demand or renewable generation varies sharply. One of the causes lies in the technological limits on how fast the different types of generators can change their output, known as ramp-up and ramp-down limits. When these limits are reached, prices

reveal the system's opportunity costs associated with the scarcity of generation technologies able to follow the variation of consumption or of renewable generation across the hours. These costs were not priced and did not appear in the PLD.

Real examples are found in international markets and widely discussed in specialized forums. For instance, an increase in consumption or a sharp drop in solar or wind generation between consecutive hours may force the operator to dispatch an expensive plant in the second hour, even if a cheaper one is not fully used. In this case, if the cost of the more expensive plant is more than twice the cost of the next cheaper one, we may observe negative prices. Similarly, a rapid fall in demand or rise in renewable generation can produce price spikes above the cost of the most expensive plant in use. In both cases, we may face situations that defy the sector's common sense. We may see generating plants producing even in hours when the price is below their variable cost, and situations in which the price exceeds the variable cost of plants that are not being used.

The possibility of an hourly PLD different from the cost of the most expensive generator sends a new message to the sector: the cost of operation depends not only on total daily consumption net of renewable generation, but also on its profile across the hours. Highly variable profiles can impose high costs because they require fast generators. These features are also influenced by the transmission network, which may be unable to evacuate the energy and may amplify the effect. However, abrupt price swings between consecutive hours are not necessarily wrong or harmful. They merely reveal a component of system cost previously hidden in charges. Bringing this new component to light can economically attract storage plants, pay hydroelectric plants correctly and encourage real demand response. **The technologies that solve the system's needs will be attracted economically, and not through subsidies or market reserves. Moreover, paying technologies correctly creates competitive pressure for innovation and is a sustainable driver of new investment.**

The massive installation of intermittent renewable generation, both utility-scale and distributed, together with reduced spare interchange capacity, generally creates the conditions for local ramp limits to be reached. It is important to stress, however, that we will not yet have negative prices in Brazil, because we have flexibility inherited from the legacy of a predominantly hydroelectric system, a still unknown effect of reduced demand due to the COVID-19 crisis, and because we use a floor (lower limit) on the value of the PLD. **In any case, these examples show that prices can depart from the rule of thumb according to which the PLD is the variable cost of the most expensive generator producing. They help shed light on the current discussion about price variations in the Northeast and show the range of challenges and opportunities for which all agents must prepare, because 2021 is just around the corner.**

Rethinking Energy Management and the Role of Generation Sources

Although we live with an oversupply of generation, there is a lack of intelligent management of hydro reservoirs and of the attributes of each source

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Valor Econômico · 23 April 2024
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ABSTRACT

Brazil's energy mix stands out after the rise of wind since 2010 and of solar over the last five years, at high voltage and in distributed generation. At times, solar is second only to hydro. Yet amid an oversupply of generation, reservoirs and the attributes of each source are poorly managed. We do not store the water needed for tomorrow's renewable uncertainty, and generators connect almost wherever they want on the network. I argue that a new price system, signaling the opportunity costs of each source's operational attributes, is imperative. Two kinds of service must be distinguished. Ancillary services are the flexibility to deviate from the schedule within milliseconds to minutes, covering whatever the schedule does not foresee in real time. Flexibility products are offers of additional ramping capability, up or down, for well-defined intervals of the daily schedule. Hydro and thermal plants supply almost all of them today. Energy, reserves and ramping should be co-optimized in the daily schedule with guaranteed deliverability through the network. These services would be priced at marginal cost alongside the spot price. Every contributing source would be paid on an equal footing. The water value must also be updated consistently. Only then will we discover which technologies and mix will prevail.

With the rising use of intermittent renewable energy (wind and solar), Brazil stands out for its energy mix. After a strong surge of wind power since 2010, solar has become prominent over the last five years with a strong expansion, both at high voltage and in its distributed form (distributed generation, DG). At certain times of the day, this source reaches second place in electricity generation, behind only the traditional hydroelectric plants.

Yet although we live with an oversupply of generation, there is a lack of intelligent management of hydro reservoirs and of the attributes of each source. Today we do not store the water needed to offset tomorrow's renewable uncertainty, and generators connect practically wherever they want on the network, even though we know how important it is for generation expansion to be coordinated with transmission expansion. Given the challenges inherent in the energy transition and climate change, which force us to deal with large uncertainties in the use of renewable generation resources, the country needs to improve the way it manages its electricity and energy resources.

The question is not only how much energy is generated, but how it is managed over time, transported across the network and absorbed by consumers. A power system full of intermittent renewable resources is in need of generators with a great deal of operational flexibility and of storage resources. In this context, a new price system, able to signal the true opportunity costs of the operational attributes of each source, becomes more than necessary; it is an imperative.

Ancillary services cover the flexibility that generators can offer to deviate from their nominal operating point on time scales from milliseconds to minutes. In other words, it is the short-term flexibility needed to handle uncertainties and phenomena not modeled in the market-based scheduling process. They allow the operator not only to keep the system synchronized in real time, handling instantaneous variations in load and generation, but also to compensate for the unavailability of generators and lines in contingencies, or even to compensate for larger errors in solar and wind generation forecasts.

On the other side are flexibility products, less explored in practice. The definition of flexibility can be quite broad and can even encompass

network aspects. Even so, these products have been widely associated with offers that agents make to provide the system operator with additional capacity to vary generation, up or down, to be used in well-defined time intervals of the daily schedule. In general, they consist of generation ramping capability, or of any other resource that reproduces this effect, such as demand reduction.

Described this way, there seems to be some conceptual overlap between the two. However, the difference becomes clear from the way each is used. Put simply, flexibility services aim to attract more ramping resources into the operator's nominal schedule, whereas ancillary services are used for everything else that the schedule does not cover in real-time operation.

Conventional controllable sources, hydroelectric and thermal plants, dominate the provision of all these services in Brazil. Almost all the forecast errors of the wind and solar generation absorbed by the system today are resolved by hydroelectric plants at the stage of adjusting the daily schedule, and by all the sources that take part in ancillary services in real time. Thus, given the great relevance that compensating for the uncertainty, lack of inertia and variability of renewables takes on in the energy transition, a review of the remuneration system is a priority. Notwithstanding, every source that contributes to this role must be paid on an equal footing. Only then will we be able to discover, and not define, which technologies and which mix of sources will prevail in the future of the system.

We have a broad menu for providing these services: from the traditional hydroelectric plants and fast thermal plants already installed and operating, through pumped-storage plants and batteries, to the famous demand response, which, depending on the price, could encourage the emerging retail market to create products never seen before (here in Brazil). But for this to work, we need a new scheme for the daily generation schedule. In it, the products energy, reserves and ramping flexibility must be co-optimized with guaranteed deliverability through the network.

On the regulatory side, the market also needs to be adjusted to come closer to the new operational reality. We need prices that reflect the

opportunity costs of the services provided by each source. Just as today we obtain from the daily schedule the marginal operating costs that give rise to the spot price (PLD), the short-term energy price that settles the differences between contracts and generation, we would also obtain the marginal costs of these new services. Thus, while the PLD pays generators for what is expected to happen the next day, the prices of flexibility and of ancillary services would pay agents according to their ability to vary energy across the hours and to respond in real time. These new prices would complement the remuneration scheme based on marginal costs, which is currently criticized for not reflecting the value of the energy resources that make it possible to absorb the uncertainty of renewables. They would help rebalance the value of the sources, reflecting in their commercial attractiveness, in a transparent and economically coherent way, the roles they play.

This is an evolution of the price system as natural and necessary as that of the hourly prices implemented in 2021. It is supported by the literature and by the practice of most of the world's developed electricity markets. Beyond that, to ensure that these services are sustainable over the years, the calculation of the water value, performed by the medium- and long-term models, must also be updated consistently. Only then will hydroelectric and thermal plants be coordinated so as to store the water needed to guarantee these services in the future.

A new system with prices for ancillary services and flexibility co-optimized with energy would not be the solution to every problem, but it would set a direction for investment that is less myopic about the new roles of the sources.

Chapter 5

Expansion by Subsidy and the Consumer's Response

2024–2025

In this chapter

Revolution in Electricity Retail Challenges Regulation 72
The Saga of Subsidy-Driven Expansion in the Power Sector 76

Introduction

By 2024, residential consumers had done what the regulation assumed they could not do. Distributed generation is produced by small solar plants connected to distribution networks. A loophole in the rules allowed its credits to be allocated to other consumer units in the same concession area. Consumers used it to finance a parallel market for these credits inside the distribution companies, saving roughly 20% on their bills. They had no other channel. In the regulated contracting environment, households must buy energy at a regulated tariff from the local distribution company and cannot choose their supplier. The episode showed that consumers, long imagined as static, respond to prices on a large scale once the rules leave them a way to do so.

I read this as a lesson about how markets form. Given scarcity and the freedom to cooperate and exchange, markets emerge and adapt even under adverse rules, much as life adapts to the pressures of its environment. Putting obstacles in the way of consumer liberalization is therefore counterproductive. The sector needs a definitive agenda for an economically correct, efficient, and ethical transition to free choice. If households could enter the free contracting environment, where consumers choose their supplier, strong segments would find it harder to sustain claims that benefit only themselves. Distributed generation would also have to compete with retail suppliers selling energy from centralized plants with much lower capital costs. The risk lies in the old lobbying playbook. Each agent fights for its own subsidy, injunction, or legislative rider, and the sector falls into a prisoner's dilemma. Cooperation would benefit everyone in the long run, yet each agent's best individual strategy is to refuse it.

In February 2025 I turned to the cost of subsidies. The Energy Development Account was created in 2002 by Law 10.438, with a clear purpose, a budget adjusted to market growth, and an end date in 2027. In 2013, Provisional Measure 579 eliminated the end date and added new subsidies. The account then jumped from less than R$5 billion in 2012 to a little over R$40 billion in 2024. Wind and solar, which receive a discount on the network-use tariff, are among the sources that account

for the largest share of these subsidies. The composition of the mix also changed in a way the totals do not show. Hydro plants produced about 89% of generation in 2010, and renewables still produced 87% in 2024. Non-controllable sources, however, grew from less than 1% of total generation in 2010 to 30% of the renewable share in 2024, and the controllability of the system fell.

Until 2010, controllable plants provided energy and flexibility together, and consumers paid for the bundle through the price of energy, in reais per megawatt-hour. Wind and solar then gained presence as suppliers of energy and, at the same time, consumers of flexibility, and the market design was never updated. The result is a triple subsidy. The first is direct, the discount on the network-use tariff. The other two are indirect. Controllable sources compensate for the uncertainty of renewables without proper payment, and renewables neither bear that cost nor have an incentive to invest in batteries. Instead of acting on this cause, the Ministry of Mines and Energy began to discuss capacity auctions for hydro plants, thermal plants, and batteries. I called this the "saga of subsidy-driven expansion", in which market reserves subsidize the expansion of one source to solve the problem created by the subsidized expansion of another.

Core ideas

1. The distributed-generation credit market showed that residential consumers respond to prices on a large scale, saving roughly 20% on their bills through a parallel market inside the regulated one.
2. Markets emerge whenever scarcity meets the freedom to cooperate and exchange, so obstructing consumer liberalization is counterproductive.
3. When each agent fights for its own subsidy, injunction, or legislative rider, the sector falls into a prisoner's dilemma.
4. The Energy Development Account lost its end date in 2013 and grew from less than R$5 billion in 2012 to a little over R$40 billion in 2024.

5 Renewables kept about the same share of generation between 2010 and 2024, but non-controllable sources grew from less than 1% of total generation in 2010 to 30% of the renewable share in 2024.

6 Wind and solar supply energy and consume flexibility, and an outdated design gives them a triple subsidy, one direct and two indirect.

7 Capacity auctions by source repeat the playbook, using market reserves to fix the problem created by earlier subsidies.

Conclusions

In these years, consumers showed that they respond to prices whenever regulation leaves them a channel, while the subsidy system responded to its own side effects with new subsidies. The consumers' response points toward liberalization and correct price signals. The subsidy system points toward the capacity auctions of 2026, which Chapter 7 analyzes.

The articles

Revolution in Electricity Retail Challenges Regulation, in Valor Econômico on 19 June 2024, reacts to the explosion of the distributed-generation credit market and draws from it the case for consumer liberalization. *The Saga of Subsidy-Driven Expansion in the Power Sector*, in Valor Econômico on 14 February 2025, uses the history of the Energy Development Account and the debate on capacity auctions to show how the sector fixes the side effects of subsidies with more subsidies. It also announces that the lack of a real-time market to price flexibility would be the topic of my next article, which opens Chapter 6.

Revolution in Electricity Retail Challenges Regulation

The explosion of the distributed-generation credit market warns us that it is counterproductive to put obstacles in the way of consumer liberalization

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ABSTRACT

The explosive and controversial market for distributed-generation credits shows that residential consumers, long imagined as unable to react to prices, respond on a large scale. Through a regulatory loophole, consumers financed a parallel market for these credits inside the distribution companies, saving roughly 20% on their bills. I argue that what blocked their response was the very design of the regulated market, where households must buy from the local distribution company at a regulated tariff. Markets develop much as life does. Given scarcity and the freedom to cooperate and exchange, they emerge and adapt even under adverse rules. Creating obstacles to consumer liberalization is therefore counterproductive, and the sector needs a definitive agenda for an economically correct, efficient and ethical transition to free choice. Opening the free market to households would make self-serving claims by strong segments harder to sustain. It would also force distributed generation to compete with retail suppliers selling energy from centralized plants with far lower capital costs. The risk is the old lobbying playbook, a prisoner's dilemma in which each agent fights for its own subsidy, injunction or legislative rider. Other parallel markets will appear, and the sector's institutions must now advance liberalization and the correction of price signals.

The recent turn toward retail, and toward the explosive and controversial market for distributed generation (DG) credits, offers some interesting insights into the future of the sector.

Consumers, once imagined as static and unable to react to prices, outflanked the sector and responded on a large scale. At the first loophole in the regulation, which allowed DG credits to be allocated to consumer units within the same concession area, consumers financed the creation of a genuine parallel market for these credits. It is a market operated from inside the very guts of the distribution companies, where savings of roughly 20% eased the expenses of thousands of residential consumers burdened by excessive subsidies and sector inefficiencies. However, the advance of this market shows how hard it is for the sector to define a coherent pro-market agenda, and it brings to light the harmful effects of postponing liberalization and keeping misguided price signals.

The plain truth is that what prevents consumers from responding is the very design of the regulated contracting environment (ACR), the market segment in which residential consumers are obliged to buy energy at a regulated tariff from the local distribution company. Unable to choose their supplier, consumers therefore responded with a new business model that gave them an unprecedented cost reduction. They cooperated with DG developers in shared-bill schemes and financed new technologies to manage bills far more efficiently than some distribution companies do. Moreover, in response to the lower costs brought by the DG discounts, significant increases in consumption were observed in the units that joined this scheme.

A great lesson for the sector: when certain conditions are present and there is freedom of choice, the cost of the scarcity of a good or service acts as a potential force that presses on the entire economic, technical and regulatory circuit linking producers and consumers. The pressure created by scarcity pushes ideas and innovation, which in turn seep through the pores of regulation, finding the shortest paths to the ocean of consumers' money. DG and residential consumers created an example of a market emerging within a regulated segment, a segment conceived precisely because it was thought that a market could not, or should not, exist there. Legitimate or illegitimate, fair or unfair, we have to admit

that it is an extremely important phenomenon to understand. It is a case study with many nuances and lessons for the next steps the sector must take to secure a sustainable future for consumers.

Keeping things in proportion, the development of markets follows mechanisms analogous to the organic mechanisms that sustain the evolution of life. No one knows exactly how life began, but, given the right conditions, it emerges and develops in harmony with the physical and chemical mechanisms intrinsic to nature. It resists and adapts to the pressures of its environment, finding equilibria quite different from the original one. This biological analogy is not merely poetic; it is also pragmatic. It reminds us that markets develop in harmony with the social and cooperative nature of humankind, finding ways to adapt and prosper even in the face of challenging regulations. It is imperative, therefore, that when we design new policies and regulations we take into account the natural propensity of markets to emerge organically whenever there is a possibility of cooperation and exchange in response to scarcity. As cooperation between consumers and the system becomes ever more relevant, I believe this is the case here.

Therefore, the explosion of the DG credit market warns us, loud and clear, that it is counterproductive to put obstacles in the way of consumer liberalization, as we have seen in recent attempts. In this sense, it seems more reasonable and productive to focus all our efforts on building a definitive sector agenda for the transition. In this agenda, we must give priority to identifying the economically correct, efficient and ethical mechanisms for the transition from the current model, which played an important role in the past, to a new one based on free choice and market arrangements.

Extending the free contracting environment (ACL) to residential consumers has a potential structural benefit. Claims by powerful segments of the sector for decisions that clearly benefit only the segment in question will be much harder to sustain in an atomized market. The COVID Account is one example. Liberalization itself will act as a counterweight to the unbridled growth of DG, which will have to reinvent itself when it must compete with retail suppliers selling energy from centralized plants with much lower capital expenditure. A new

equilibrium will have to emerge, and DG will have to adapt its business model. Beyond that, we will also be forced to revisit how subsidies are distributed between the ACR and the ACL. Difficult conversations will have to take place.

Nevertheless, the risk is falling back on the old lobbying playbook. Many will prefer to keep the ACL and the ACR just as they are, with low prices on one side and a market reserve with a high regulated tariff on the other. And this is where the great evil that keeps the power sector from moving forward lies: the corruption at the very genesis of the agenda for change in the sector. In the current *modus operandi*, instead of discussing how to guarantee free choice and the right price signals for a more sustainable balance among sources, we end up fighting for more individual subsidies. We thus fall into a variant of the famous prisoner's dilemma of game theory. In this dilemma, we know that cooperation among all agents would generate greater long-term benefits for everyone. However, given the *status quo*, an agent's best individual strategy becomes not to cooperate and to fight for its own subsidy, injunction or pet legislative rider (jabuti). This is more or less how the famous John Nash, who proved the existence of this kind of equilibrium in non-cooperative games, would explain the situation we are living through today in the power sector.

It is a matter of time before other parallel markets appear in response to the neglect of residential consumers, who have already shown that they can respond to price signals. Now it is the sector's institutions that must rise to the occasion and move forward with the agenda of liberalization and of correcting price signals and incentives.

The Saga of Subsidy-Driven Expansion in the Power Sector

The country uses market reserves to subsidize the expansion of one source in order to solve the problem created by the subsidized expansion of another

Original title: *A saga da expansão por subsídios no setor elétrico*
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ABSTRACT

I argue that the Brazilian power sector tends to fix the side effects of subsidies with more subsidies, and I use the Energy Development Account and the capacity auctions to show it. The account was created in 2002 with a clear purpose, a budget tied to market growth and an end date in 2027. In 2013 the infamous Provisional Measure 579 eliminated that end date and added new subsidies. The account then jumped from less than R$5 billion in 2012 to a little over R$40 billion in 2024. Wind and solar sources, which receive a discount on the network-use tariff, are among the main beneficiaries of these subsidies. Renewables still supplied 87% of generation in 2024, close to the 89% that hydroelectric plants alone produced in 2010. Non-controllable sources rose from less than 1% of generation to 30% of the renewable mix, and the system lost controllability. These sources supply energy but consume flexibility, and the market design was never updated. The result is a triple subsidy, one direct and two indirect. Source-specific capacity auctions repeat the same playbook with market reserves, without a real-time market to price flexibility. Legislators and regulators should avoid simple solutions to complex problems and draw on the more impartial views of academia.

The Brazilian electricity market faces structural challenges aggravated by a system of subsidies that has lost its original direction. The case of the Energy Development Account (CDE) is emblematic of how the imbalance generated by poorly designed public policies and the prolonged maintenance of unnecessary subsidies can cause a regulatory "short circuit" and compromise, with cascading effects, the sustainability of an entire sector. This article aims to illustrate, through the example of the CDE and of the capacity auctions, the tendency of the Brazilian power sector to try to fix the side effects caused by subsidies with more subsidies.

Created in 2002 by Law 10.438, the CDE had a clear objective: to promote energy development in Brazil, ensuring universal access to electricity and financing strategic subsidies for renewable sources. The CDE also had a predictable logic, with a budget adjusted to market growth and a set date for its extinction in 2027. This original model sought balance and efficiency in the allocation of resources without generating excessive tariff impacts.

In 2013, after the infamous Provisional Measure 579 (Law 12.783), the original purpose of the CDE was disfigured. The 2027 end date was eliminated and new subsidies were added to the account, such as new incentives for renewables and for coal and the reimbursement of the supply costs of isolated systems. The impact of this measure was the start of an exponential growth of the CDE, which jumped from less than R$5 billion in 2012 to a little over R$40 billion in 2024. The absence of a clear limit turned the account into a practically unlimited mechanism for transferring resources, steered by political lobbies and far from transparent agendas.

Among the sources that account for the largest share of the subsidies in the CDE today are the intermittent, non-controllable renewables (wind and solar). These sources (also known as incentivized sources, because of the incentives granted by current regulation) were, and will continue to be, essential for diversifying the energy mix, but they have reached a stage of maturity that calls for a review of their subsidies. One of the incentives granted to these sources is the discount on the network-use tariff (the cost of using the transmission system), which

in practice splits the benefit between the generator and the consumer. However, maintaining these incentives has created structural imbalances among sources and distorted countless market incentives.

Until 2010, non-controllable renewable sources accounted for less than 1% of total generation in Brazil. Hydroelectric plants, in turn, being controllable renewable sources, produced approximately 89% of the country's total energy that year. In 2024, the share of total renewable generation in Brazil remained practically the same, reaching 87% of total generation. However, the share of non-controllable sources within the renewable mix grew significantly, to 30% of it. As a result, the controllability of the Brazilian power system was significantly reduced between 2010 and 2024.

In this context, until 2010, conventional controllable generation was the main provider of energy and flexibility (where, for simplicity, I include the controllability needed to meet peak load, the flexibility to vary output, and all ancillary services). Consumers paid for this bundle of services through the quantity traded of the former, that is, through the energy supplied, in reais per megawatt-hour. From 2014 onward, however, a new type of agent gained a larger presence in the market and challenged the prevailing design: the non-controllable renewables. Interestingly, these sources entered the market acting simultaneously as suppliers and consumers, supplying energy but consuming flexibility. Yet the Brazilian market, going against international experience, did not update itself for this new scenario.

This mismatch created a strong disincentive for controllable sources, which are used to guarantee that peak load is met, and it amounts to a triple subsidy to non-controllable renewables. The first is the direct sector subsidy, stemming from the discount on the network-use tariff. The second and the third are indirect and stem from the lack of a level playing field among sources created by an outdated market design. While controllable sources are today obliged to compensate for the uncertainty and inflexibility caused by non-controllable renewables, without being properly paid for it, non-controllable renewables are neither required to bear these costs nor encouraged to invest in batteries.

Instead of acting directly on the cause of this enormous imbalance, the Ministry of Mines and Energy began to discuss capacity auctions for hydroelectric plants, thermal plants and batteries. The risk, however, is that we follow the same playbook that brought us here, only now with the controllable sources. When it comes to subsidies, the easiest solution is, in general, the worst possible one. We are already discussing auctions by source, and the dispute over which technology will take the first share of the demand for flexibility has already begun. Much of the current discussion about new capacity and energy auctions, and about which source should have preference to supply each type of product, ignores the intrinsically multi-attribute nature of the sources and current knowledge about efficient ways to auction these services.

Moreover, we are discussing the long-term pre-contracting, under great uncertainty, of enormous blocks of capacity and flexibility for real-time operation, without even having a real-time market to price flexibility deficits and to pay those who have been providing it for years (a topic for my next article). This is the saga of subsidy-driven expansion in the Brazilian power sector: we will use market reserves to subsidize the expansion of one source in order to solve the problem created by the subsidized expansion of another.

Without falling into the cliché that the lobbies are to blame, I believe everyone has the right to defend their points of view and solutions. Nevertheless, legislators and regulators have the final word. They should therefore protect themselves from the trap of simple solutions to complex problems. They forget that they have the whole of academia at their disposal, which can provide more impartial views and contribute to more effective decisions.

Chapter 6

In Search of Lost Flexibility

2025

In this chapter

In Search of Lost Flexibility 85
Pricing Energy and Flexibility in the Electricity Market 91

Introduction

In the 1980s and 1990s, international flights often used large Boeing 747s, and each passenger could check up to two 32-kg bags at no extra cost. Space was abundant, the marginal cost of a bag was low, and airlines sold an all-inclusive fare. When smaller, more fuel-efficient aircraft made luggage compete with passengers, airlines began to charge for seats and bags separately. I used this story in 2025 to explain the Brazilian electricity market. The parallel is not perfect, but in 2004, when the last sector reform was made, the system was 90% hydroelectric, and hydro plants offered enormous short-term flexibility. The design we adopted charged only for energy, the scarce product, and assumed that flexibility would come bundled at zero marginal cost.

Until 2010, about 90% of generation was hydroelectric and practically all the rest thermal, which gave the supply a high degree of control. From 2010, Brazil encouraged wind and solar with subsidies meant as an initial push, and the push became unbridled, uncoordinated growth of non-controllable sources in the transmission network and in distribution. Load grew about 45% between 2010 and 2024 and the construction of new reservoirs stopped, so wind and solar filled the gap. These sources deliver energy and consume flexibility. In the Northeast, 6 MWh of hydro generation are held as secondary reserve for every 100 MWh of expected wind generation. Secondary reserve is one of the ancillary services that keep the system balanced in real time. These services are neither priced nor paid according to supply and demand. The critical point came on 15 August 2023, when a blackout affected 25 states and the Federal District. The operator then began to curtail wind and solar output far more often, and distributed generation began to reverse power flows in distribution networks.

Capacity auctions emerged as the solution of the moment. They copy the rigid long-term contracts of the regulated market, indexed to the official consumer price index. The auctions also reserve demand for specific sources and give priority to thermal plants whose variable costs may exceed the cap on the spot price. They also conflict with the shorter contracts of the free market and with the liberalization planned

for 2030. The alternative was already on the table in Public Consultation No. 33, of 2017. One of its most important steps is the development of sequential real-time markets. In these markets, a generator that fails to deliver what it scheduled buys its shortfall at the real-time price and thereby pays whoever supplied the flexibility, whatever the technology. Demand response showed that consumers can supply this flexibility. A voluntary program created by the regulator in 2022 gave large consumers an explicit, offer-based market for the daily dispatch of their reductions, and it had already exceeded 9 GWh in October 2024. The program also showed how far prices were from the real cost of operation. The spot price often stayed below R$100/MWh, while thermal plants dispatched outside the price-formation models recorded variable costs above R$1,000/MWh.

The last place to search is distribution, which I called the "deep system" because it is the deepest and least explored layer of flexibility in the sector. It is a "pre-salt" of flexibility, with large reserves that are harder to exploit. Distributed generation with automated curtailment and storage, smart tariffs, and residential and commercial automation can be aggregated, and the resulting flexibility traded in real time between the distribution companies and the national operator through aggregators. This requires new communication protocols between the national operator and the distribution system operators. In August 2025 I closed the argument with a prescription. Flexibility must be treated as a set of products distinct from energy, charged to those who demand it and paid to those who supply it. In Texas, batteries already provide 90% of frequency regulation and earn a large share of their revenue in ancillary-service markets. Locking the sector for decades into source-specific capacity contracts, without improving the short-term market, would only deepen its lack of competition.

Core ideas

1 Until 2010, a generation mix of about 90% hydro and almost all the rest thermal gave the Brazilian supply a high degree of control.

2 Subsidies meant as an initial push for wind and solar became uncoordinated growth of non-controllable sources in transmission and distribution, and the blackout of 15 August 2023 marked the critical point.

3 The 2004 design charged only for energy and assumed that flexibility came bundled at zero marginal cost, like the all-inclusive fares of the Boeing 747 era.

4 Load grew about 45% between 2010 and 2024 and reservoir construction stopped, so flexibility became scarce while ancillary services remained unpriced.

5 Capacity auctions copy the rigid, inflation-indexed contracts of the regulated market, reserve demand for specific sources, and conflict with the liberalization planned for 2030.

6 Sequential real-time markets, already proposed in Public Consultation No. 33, pay whoever covers a deviation at the marginal operating cost, whatever the technology.

7 The demand-response program created in 2022 exceeded 9 GWh in October 2024 and exposed spot prices often below R$100/MWh while thermal plants outside the price models cost over R$1,000/MWh.

8 Distribution is the deepest layer of flexibility, and reaching it requires aggregators and new protocols between the national operator and the distribution system operators.

Conclusions

By 2025 the cause of the loss of flexibility was clear. The 2004 design priced only energy, subsidies multiplied the sources that consume flexibility, and the market offered no price to those who supply it. The way out combines real-time markets, prices for ancillary services, and the flexibility of consumers and distribution networks. The first of these has been on the table since 2017. As I wrote at the end of *Pricing Energy*

and Flexibility in the Electricity Market, we need a middle path, one that is more structural and sustainable.

The articles

In Search of Lost Flexibility, published by MegaWhat on 7 March 2025, is the article announced at the end of the previous chapter. It dates the loss of flexibility, criticizes the capacity auctions, and presents real-time markets, demand response, and distribution networks as the places where flexibility can be found. *Pricing Energy and Flexibility in the Electricity Market*, in Valor Econômico on 25 August 2025, explains the problem through the unbundling of airline fares, documents the three subsidies to renewables, and argues that flexibility must be priced as products distinct from energy.

In Search of Lost Flexibility

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MegaWhat · 7 March 2025
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ABSTRACT

Until 2010, about 90% of Brazil's generation was hydroelectric and almost all the rest was thermal, which gave the system high control over supply. Subsidies meant as an initial push for wind and solar turned into unbridled, uncoordinated growth of non-controllable sources in transmission and distribution. The blackout of 15 August 2023, which affected 25 states and the Federal District, marked the critical point. Curtailment became frequent, and distributed generation caused reverse flows in distribution networks. The capacity auctions that emerged as the solution of the moment copy the rigid, inflation-indexed long-term contracts of the regulated market, create source-specific market reserves and conflict with the liberalization planned for 2030. I argue that the reform agenda of Public Consultation No. 33 already offers the alternative. In sequential real-time markets, whoever fails to deliver buys the shortfall at the real-time price and pays whoever supplied the flexibility, regardless of technology. The demand-response program created in 2022 exceeded 9 GWh in October 2024. It exposed spot prices often below R$100/MWh while thermal plants dispatched outside the price models cost over R$1,000/MWh. The last stage of this search is distribution, a "pre-salt" of flexibility to be unlocked by aggregators and new protocols between the national operator and distribution system operators.

The Brazilian power system was once predominantly based on controllable, or flexible, generation sources. Until 2010, about 90% of generation was hydroelectric and practically all the rest was produced

by thermal plants, which gave the supply of energy a high degree of control in the face of short- and long-term fluctuations in demand.

To expand the energy mix with renewable and diversified sources, taking advantage of its high controllability, Brazil encouraged the installation of wind and solar farms from 2010 onward. The goal was to curb the use of fossil-fueled thermal plants and to reduce dependence on hydroelectric plants with large reservoirs, which have a greater environmental impact. Initial support for these technologies was based on subsidies that sought to accelerate their competitive maturity.

However, as described in the article "The Saga of Subsidy-Driven Expansion in the Power Sector" ("A Saga da Expansão por Subsídios do Setor Elétrico", Valor Econômico, Opinion column, 14 February 2025), the original purpose of these subsidies was significantly subverted. Instead of serving as an initial push for new sources, they became a mechanism that distorted the sector's expansion, promoting the unbridled and uncoordinated growth of non-controllable resources in both the bulk transmission network and the distribution network.

This growth reached a critical point on 15 August 2023, when a large-scale blackout affected 25 states and the Federal District. Prominent among the causes of the incident was the inadequacy of the response times that wind farms had reported to the National Electric System Operator (ONS), which compromised the reliability of power-balancing services.

In response, the ONS began to curtail wind and solar generation for operational reasons far more frequently. At the distribution level, the problem appeared both commercially, with distributed generation (DG) challenging the regulated market and reducing consumption by thousands of megawatts, and technically, with reverse power flows affecting protection systems and overloading transformers. Thus, although the ONS has neither the authority nor the technical capability to perform the same curtailments it carries out at high voltage, some distribution companies began to hinder new DG connections administratively.

Against this backdrop, capacity auctions emerged as the solution of the moment. With strong participation by thermal plants and contracts

very similar to the old availability contracts, flexibility was defined by formulas that favor sources with shorter response times and lower minimum generation. Although this initiative has the potential to attract new generators that contribute flexibility to the system, the strategy has clear limitations that are important to note:

First, capacity auctions mimic the long-term contract model of the regulated environment, which has already proved both expensive, because of its indexation to the official consumer price index (IPCA), an index disconnected from the sector, and excessively rigid in dealing with medium- and long-term fluctuations in demand. Nevertheless, the long-term design continues to be adopted despite the great uncertainty about the real future demand for these products and the downward trend in the costs of new storage technologies and other sources.

Second, these auctions will create market reserves, with source-exclusive auctions and priority for thermal plants whose variable costs may exceed the cap on the spot price (PLD, the settlement price for differences), without attacking the root of the problem: excessive subsidies and the lack of market price signals aligned with operational reality. Moreover, the new auctions conflict with the idea of expansion based on shorter contracts (generally up to five years), widely traded in the free contracting environment (ACL) and fundamental to the logic of the sector's liberalization planned for 2030.

In contrast to the strategy adopted by the Ministry of Mines and Energy (MME) to obtain new flexibility through capacity auctions, there is the reform agenda for the design of the short-term market set out in the results of Public Consultation No. 33 (CP 33). One of the most important steps in this direction is the development of sequential real-time markets. In these markets, whenever a generator committed to delivering a given number of megawatt-hours fails to meet its obligation, it must buy its shortfall at the real-time market price, thereby financing the generators that showed flexibility by adjusting the levels scheduled for them the day before to compensate for the imbalance caused.

Thus, it does not matter whether the deficit was covered by a hydroelectric plant or by hybrid plants with storage. Payment for the cost caused will go to those who solved the problem, regardless of the

source. Moreover, this payment will be based on the system's marginal operating cost, encouraging any innovation that brings the flexibility needed at each moment. In this way, the real-time market not only optimizes the use of resources throughout the day with greater precision but also creates a nondiscriminatory, technology-agnostic mechanism, remunerating all those who, through their flexibility, help offset the deficit generated by inflexible resources. This corrects many of the current injustices of our market design.

One exception to the current drift away from a pro-market agenda for encouraging flexibility in the sector is the new voluntary demand response (DR) program. Established by Normative Resolution No. 1.040/2022 of the Brazilian Electricity Regulatory Agency (ANEEL), this historically underestimated resource seems to have finally found its timing and its appropriate design in the Brazilian power sector. Moreover, DR has come to demonstrate, once and for all, that consumers do in fact respond to price signals.

The new DR programs gave large consumers a leading role in the discussions about how to obtain flexibility in the power sector. Innovating with a pro-market format, the ONS and the Electric Energy Trading Chamber (CCEE) created an explicit offer-based market for the daily dispatch of DR, which had already exceeded 9 GWh in October 2024. With DR, the operator can tap a vast and unexplored potential of industrial flexibility, remunerating essential services that were previously performed exclusively by generators.

Moreover, DR revealed a glaring discrepancy in the sector: while the spot price (PLD) often stayed below R$100/MWh, thermal plants dispatched outside the price-formation models, in the process known as post-DESSEM (after DESSEM, the day-ahead scheduling model), recorded variable costs above R$1,000/MWh. DR thus showed that the sector's prices do not reflect, not even remotely, the real operating costs of serving load, as they should. The benefits DR has demonstrated for the system are therefore clear:

1. It remunerates consumers' offers for services voluntarily provided to the system, based on the system's real demand for flexibility and

at prices associated with the opportunity cost of displacing more expensive, fossil-fueled thermal plants.

2. It creates a new and significant source of revenue for consumers, who are paid above their opportunity costs for providing flexibility that was often available and unused.
3. It adds to the operator's menu a high-value product with almost instantaneous responses, which, although still incipient in Brazil, features in many markets in more mature systems, from medium-term auctions to ancillary services.
4. Finally, it is an excellent promoter of the mitigation of renewable curtailment and of emissions reduction, and it opens the way for new technologies and new business models that will promote efficiency in the use of distributed resources.

Finally, here we reach the last stage of the search for flexibility. We reach the distribution companies, the "deep system", the deepest and still unexplored layer of flexibility in the power sector.

The distribution companies represent the discovery of a "pre-salt" of flexibility. But just as the reserves are large, they are also somewhat harder to exploit. The challenges involve regulatory reform and technology.

Developers can create new DG products with automated curtailment and storage through specialized apps, to avoid increasingly divergent tariffs for injected and consumed energy. On the other side, smart tariffs can engage consumers through prices or through residential and commercial automation systems. All these services can be aggregated, and the resulting flexibility traded in real time between the distribution companies and the ONS through aggregators. However, the key to unlocking this revolution, which has already happened in several other, more mature systems that also suffered from a lack of flexibility, lies in establishing new communication protocols between the ONS and the distribution system operators (DSOs).

Although CP 33 has already outlined a positive agenda for attracting the flexibility needed to integrate more renewables with the least possible dependence on subsidies and on fossil-fuel-based generation

alternatives, the colonial extractivist idea seems to be in our DNA. We keep extracting the riches of a country with an abundance of practically every energy resource, without using a cent of this benefit to structure it for a sustainable future. "A wealth that generates no wealth." The question remains: will we finally organize this market so that it generates long-term value, or will we remain hostages to short-termism, market reserves and the champions of the moment?

Pricing Energy and Flexibility in the Electricity Market

The end result of the market design is deteriorating supply reliability, higher tariffs for consumers and a very poor signal for renewables, which could already be fully geared toward a hybrid model with batteries

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ABSTRACT

I use the unbundling of airline fares as an analogy for the Brazilian electricity market. In the 1980s and 1990s, large Boeing 747s let each passenger check two 32-kg bags under an all-inclusive fare. Smaller, more fuel-efficient aircraft made luggage compete with passengers, and airlines began to charge for seats and bags separately, a change Brazil only made in 2017. The 2004 power-sector reform, designed for a system that was 90% hydroelectric, adopted a pricing system from the Boeing 747 era. It charged only for energy and assumed that flexibility came bundled at no marginal cost. Load grew about 45% between 2010 and 2024, reservoir construction stopped, and wind and solar, which supply energy and consume flexibility, filled the gap. In the Northeast, 6 MWh of hydro generation are held as secondary reserve for every 100 MWh of expected wind generation. However, ancillary services are not priced by supply and demand, and renewables receive three subsidies, including a 50% discount on the network-use tariff. In Texas, batteries already provide 90% of frequency regulation. I argue that flexibility must be priced as products distinct from energy. Without a better short-term

market, source-specific capacity auctions would only deepen the lack of competition. We need a middle path, more structural and sustainable.

In the 1980s and 1990s, it was common for international flights to operate with large Boeing 747 aircraft, equipped with four engines and generous legroom. The excess power and size were such that each passenger could check up to two 32-kg bags. Since the binding constraint was the number of seats and the marginal cost of a bag was low, the airline industry operated under an all-inclusive model, in which passengers paid for the seat and carried luggage at no additional cost.

With globalization and intense competition, fuel efficiency became a priority, leading to smaller aircraft and a lower cost per kilogram transported. With less available space, luggage began to compete directly with passengers. The global market reacted by unbundling products: charging separately for seats and baggage, allowing a better balance between passengers' demand for kilograms of baggage and its opportunity cost for airlines.

In Brazil, regulation insisted on a single pricing model for much longer than in the rest of the world, only introducing unbundling in 2017. As a result, the inconsistency between the pricing model and the reality of the new aircraft not only delayed the country's entry into the low-cost airline revolution but also created market frictions and additional costs for consumers.

The parallel is not perfect, but in the electricity sector the current dynamics are similar. In the last sector reform, in 2004, the Brazilian system was 90% hydroelectric. These plants, although constrained in their medium- and long-term energy production by uncertain inflows, offered enormous short-term operational flexibility (the ability to quickly adjust generation to help the system operator balance supply and demand). Thus, we adopted a pricing system from the era of the Boeing 747: we charged only for the scarce product, energy, and assumed that flexibility would come bundled at zero marginal cost.

Just as aviation had to restructure its fleet to operate more efficiently, the electricity sector had to adapt to load growth, which increased by

about 45% between 2010 and 2024 alone. With the halt in the construction of new reservoirs, the only way to preserve a renewable generation mix was to expand wind and solar generation (intermittent by nature). But, unlike conventional controllable sources, which provide both energy and flexibility, wind and solar deliver only energy and consume flexibility.

For example, thermal plants are rescheduled daily to complement renewable generation, while hydro plants reduce output at midday and ramp up quickly at sunset, allowing the system to absorb both the expected generation profile and real-time wind and solar uncertainty. In Brazil's Northeast, for every 100 MWh of expected wind generation, 6 MWh of hydro generation are withheld as secondary reserve, part of ancillary services and a key element of flexibility. In the South, this figure rises to 16 MWh.[1] With the rapid expansion of solar generation, both centralized and distributed, flexibility has become scarce and has started to compete with the energy product, the only product remunerated by the short-term price and the one that backs the sale of contracts.

However, despite their crucial and growing role in compensating for renewable uncertainty and maintaining system reliability, ancillary services are neither priced nor remunerated on the basis of supply and demand, which cancels the signal of their scarcity and removes incentives for new investment in technologies that provide this flexibility.

Once again, Brazil repeats the mistake and insists on the incoherence between prices and operational reality. In addition to maintaining a single pricing scheme, the country also subsidizes technologies that consume flexibility. Today, renewables receive three types of subsidies: (1) a 50% discount on the network-use tariff, (2) exemption from contributing to ancillary services, and (3) exemption from paying for the increase in reserve requirements, supplied, for example, by hydro plants. The result of this design is deteriorating system reliability, higher consumer tariffs and very poor signals for renewables, which could already be operating in hybrid configurations with batteries. As a

[1] The South figure is 15 MWh under the criterion of the National Electric System Operator (ONS); the original publication printed 16 MWh.

reference, recent data from the Electric Reliability Council of Texas (ERCOT), the Texas system operator in the United States, indicate that batteries already provide 90% of frequency regulation, earning a large share of their revenue in ancillary-service markets.

If properly designed, these markets not only improve system reliability, by strengthening or restraining incentives for technologies capable of providing flexibility, but also create benchmarks for the pricing of long-term mechanisms. Advancing this agenda means (1) fostering new businesses in storage and demand response and (2) correcting the remuneration of thermal and hydroelectric plants, which have been providing these services for years. In such an environment, the incentive for flexibility becomes technology-agnostic and guided by the dynamics of supply and demand for this attribute, not by more subsidies. The appropriate approach, therefore, would be to treat the different types of flexibility obtained through these services as products distinct from energy, charging those who demand them and properly remunerating those who supply them.

Nevertheless, instead of designing an ancillary-services market and improving our already outdated energy market, for example, with a more granular second settlement closer to real time, we are debating a lock-in, for several decades, to the outcomes of capacity reserve auctions with widely questioned designs. These auctions include contracts with rising fixed revenues, despite the global trend of falling prices for flexibility equipment, and a market reserve for specific technologies, mostly thermal plants, with higher emissions and exorbitant variable costs. Again, the parallel is not perfect, but imagine what it would be like if, in order to travel, we had to pre-contract all the luggage we intend to take each year for the next 20 years, without knowing which trips we will take, what the market prices of tickets will be, or even whether this will still make sense over that horizon.

Expanding generation through capacity auctions for specific sources, without improving the short-term market, including flexibility, will only deepen the sector's current lack of competition, of a level playing field and of efficiency. We need a middle path, one that is more structural and sustainable.

Chapter 7

Neither Market nor Planning: The Capacity Auctions of 2026

2026

In this chapter

Neither Market nor Planning: Expansion Is by Subsidy 100
Five Problems with Brazil's 2026 Capacity Reserve Auction 104
The Power Sector and the Land of Lost Opportunities 114
The Regulatory Barrier in Brazil's Power Sector and the Battery Auction 118

Introduction

Brazil's capacity reserve auction of 18 March 2026 contracted 18,977 MW, of which 16.47 GW were thermal and 2.5 GW hydro. The annual cost is about R$38.9 billion, and the total outlay about R$515 billion over contracts of 10 to 15 years. At US$395,000 per MW-year, the price was 3.8 times that of the latest annual capacity auction of PJM Interconnection, in the United States, for 2026/27. The problem the auction meant to solve is real. In 2025 the National Electric System Operator estimated a 96% probability of loss of load from insufficient capacity by 2029 and expected curtailment in 80% of daytime hours over the following five years. The problem originates in subsidized solar generation, whose output falls at sunset and creates large ramps of net load. Net load is the demand left for controllable plants once solar and wind generation is deducted. In the four articles of this chapter I question the instrument chosen to solve it.

A capacity contract pays a plant for being available, with no obligation to deliver energy to the consumer. The consumer pays for availability through a charge and still buys the energy at market prices whenever the plant runs. Combined with the choice of specific sources, this fixed revenue works as a subsidy. It also allocates risk unevenly, because generators secure their revenue against low prices while consumers receive no right to energy that would protect them against high ones. In a crisis, generators move from the market to claims and lawsuits. The availability contracts that structured the new-energy auctions for two decades work differently, because they resemble call options. When the thermal plant is called to produce, the energy belongs to the consumer, who reimburses the plant's variable cost, and this limits the consumer's exposure to high short-term prices.

A week after the auction I argued that it follows neither of the two legitimate routes to expansion. One trusts market signals to reveal costs and guide investment. The other relies on centralized planning, with models that internalize constraints, uncertainties, and complementarities between sources. The auction has the fundamental elements of neither, so it cannot even be called a hybrid. Quantities and sources were chosen

administratively, and the auction resembles a tendered subsidy. Subsidies rarely come alone, and the government was already arranging public financing to defer tariff increases driven by earlier subsidies, at the risk of building a subsidy pyramid. In May I listed five problems of incentives: (1) guaranteed revenue creates an addiction and a race for new auctions; (2) the market design is not ready for these contracts; (3) demand is set by institutions that fear a blackout far more than a tariff increase spread over years; (4) a single buyer passes costs through and turns commercial disputes into regulatory ones; and (5) the auction invites regulatory complacency. On the second problem, Brazil has no real-time market, no proper prices for ancillary services, and no two-settlement, so projects sought almost their entire viability in the fixed revenue. Under two-settlement, each deviation from the day-ahead schedule is settled again at the real-time price. Here we tried to start from the end. Markets about fifteen years ahead of ours show that short-term price formation comes first.

In June I argued that the deeper problem is the daytime surplus, and that the evening ramp is one of its consequences. Much of the surplus comes from distributed solar inside distribution networks. Local flexibility markets in the distribution companies would attack it at its origin, together with real-time prices and two-settlement. In these markets, aggregators coordinate generators, batteries, and consumers. Relying only on capacity auctions gives up three futures: consumers who invest in batteries, distributed generation as a paid flexibility asset, and a market that integrates wholesale and retail. The pattern returned with the first battery auction of the national system, whose public consultation opened on 30 July, and I wrote about it in August. A competitive auction still has to answer administratively questions that agents facing coherent prices would answer on their own. Because the cause and the beneficiaries of storage are identifiable, a first step through the market is within reach. Two experiences show that agents respond to prices. During the 2001 rationing, consumers themselves chose more efficient appliances, and in Texas competing batteries drove down the prices of ancillary services.

Core ideas

1. The auction of 18 March 2026 contracted 18,977 MW at about R$38.9 billion a year, some R$515 billion over 10 to 15 years, at a price 3.8 times the latest annual capacity price of PJM Interconnection.
2. Capacity contracts pay for availability without delivering energy to the consumer, and combined with source selection they act as a subsidy.
3. Risk is allocated asymmetrically, since generators are protected against low prices while consumers remain exposed to high ones.
4. The auction follows neither the market route nor integrated planning, and the subsidies it creates tend to breed new ones, at the risk of a subsidy pyramid.
5. Five incentive problems follow from it: addiction to guaranteed revenue, a market design unready for capacity contracts, administratively defined demand, a single buyer that passes costs through, and regulatory complacency.
6. Markets about fifteen years ahead of Brazil show that the order of reform matters and that short-term price formation comes first.
7. The deeper problem is the daytime surplus in distribution, which local flexibility markets, real-time prices, and two-settlement would attack at its origin.
8. The battery auction of 2026 repeats the pattern, although the identifiable cause and beneficiaries of storage put a first step through the market within reach.

Conclusions

In 2026 Brazil chose an expansion route outside both the market and integrated planning, at prices far above international references and with risks borne mostly by consumers. As I wrote in August, the order matters. Prices must first tell the truth about the operation, and contracts

for capacity or storage can then complement them. When capacity is contracted before prices are fixed, the cost that prices fail to reveal is transferred to the fixed revenue of the contracts.

The articles

Neither Market nor Planning: Expansion Is by Subsidy, in CNN Brasil on 25 March 2026, a week after the auction, contrasts it with the two legitimate routes to expansion and warns of a subsidy pyramid. *Five Problems with Brazil's 2026 Capacity Reserve Auction*, on LinkedIn on 20 May 2026, sets out the five incentive problems in detail, with the international evidence for putting prices first. *The Power Sector and the Land of Lost Opportunities*, in Valor Econômico on 9 June 2026, sets the auction against the operator's own warnings and the daytime surplus and names the three futures it gives up. *The Regulatory Barrier in Brazil's Power Sector and the Battery Auction*, in CNN Brasil on 19 August 2026, applies the same reasoning to the first battery auction.

Neither Market nor Planning: Expansion Is by Subsidy

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ABSTRACT

On 18 March 2026, Brazil's capacity reserve auction contracted 18,977 MW at about R$38.9 billion a year, some R$515 billion over 10 to 15 years. The values exceed almost every international benchmark, but my concern is the way of expanding the system that the auction creates. The problem is real. Subsidized intermittent renewables created large solar net-load ramps. Capacity contracts, however, pay plants for availability with no obligation to deliver and settle energy. Generators secure revenue against low prices, while consumers pay through charges with no energy right to protect them from high prices. In a crisis, generators turn from the market to claims and lawsuits. Quantities and sources are chosen administratively, so the auction resembles a tendered subsidy. It follows neither of the two legitimate routes to expansion, the market and centralized planning, and is not even a hybrid. Subsidies rarely come alone. The government is already arranging public financing to defer tariff increases driven by past subsidies, which added R$50 billion to the Energy Development Account last year. The risk is a subsidy pyramid. Before making these auctions the axis of expansion, we must ask whether they contract flexibility, capacity and energy efficiently or merely repeat the usual shortcut.

The capacity reserve auction (LRCAP) held on 18 March 2026 contracted 18,977 MW of capacity, with estimated investments of R$64.5 billion, an annual cost of approximately R$38.9 billion and a total outlay of about R$515 billion over the 10 to 15 years of the contracts. These values exceed

practically every international benchmark and the levels of required revenue observed in previous auctions in the country itself. But the point of this article lies elsewhere: not in the price, but in the market design and the way of expanding the system that we are creating.

The idea of the LRCAP is simple: to contract additional capacity to guarantee security and flexibility in meeting demand peaks or ramps. The origin of the problem is also clear: the large net-load ramps caused by solar generation, a direct consequence of a disorderly expansion driven by subsidies to intermittent renewables (centralized and distributed). The question, therefore, is not whether there is a problem; it is already clear that there is. The question is how to solve it.

In this auction, we used the idea of capacity contracts, which remunerate plants for the availability of their capacity but create no obligation to deliver and settle a given quantity of energy in the market over the contract period. However, since different generation sources provide energy and capacity in different proportions over time, the risk is that we are not using the appropriate products and mechanisms to contract an efficient portfolio of sources to solve the system's problem.

This risk materializes in several ways. For example, in a capacity auction with low competition, generators, who rightly seek to reduce risk, tend to bid so as to be fully viable on capacity revenue alone, disregarding the profit from selling energy, even in a scenario of structurally high prices. This also stems from the numerous availability clauses that impose several non-trivial risks on generators.

In this scenario, the mechanism fails to reveal the value of the capacity attribute on its own and ends up inducing payment for the full package. However, the result is asymmetric: while generators secure their revenue against low-price scenarios, the consumer, also risk-averse, does not receive the right to the energy settlement that protects it against high-price scenarios.

Worse still, in times of crisis, generators' incentives can become completely misaligned. Instead of fighting for the evolution of the regulatory design so that prices reflect operational reality, aligning their interests with those of the system, generators start to concentrate their efforts on negotiating contractual clauses that relieve them

of responsibilities through claims and lawsuits. Out goes value maximization through the market; in comes maximization through regulation.

Setting aside the design of the contract and looking at the auction, the definition of the quantity to be contracted and of the sources to be prioritized is made administratively, is not technology-agnostic, and makes little use of the synergies with the existing fleet. In this way, the LRCAP resembles a tendered subsidy: the contracts are not signed directly with consumers, the costs are shared out through charges and, when the contracted plants generate energy, the consumer will still have to pay in full for that production.

There are basically two legitimate and well-founded views on how to expand generation:

1. on one side, those who trust market mechanisms, price signals and the interaction between supply and demand to reveal costs and guide investment;
2. on the other, those who advocate centralized planning, supported by models capable of internalizing constraints, uncertainties and complementarities between sources and infrastructure.

Despite their differences, both schools of thought converge on essential principles, such as transparency, technically grounded decisions, efficiency and a focus on the consumer. The divergence lies in the path to get there and, above all, in who should hold the necessary information and bear the responsibility for guiding these decisions.

The problem is that, in the vacuum left by this still unresolved divergence, the path that is beginning to consolidate through capacity auctions does not adequately represent either of these two approaches. It is not a market reform, which could bring short-term prices closer to operational reality, introduce ancillary-service products and create the regulatory foundations for consumers and distributed generators in retail to respond to prices.

Nor is it a return to classical centralized planning, based on robust studies and widely debated criteria. Nor, unfortunately, can we say that

it is a hybrid of both, since we have the fundamental elements of neither model.

On 18 March 2026, we chose a new way of expanding the system, one based neither on the market nor on integrated planning, but on long-term subsidies granted to sources preselected administratively and discretionarily. Moreover, the calculation of the auction's demand and the selection of projects rest on unrealistic assumptions about the contribution of the sources, which makes the mechanism hardly transparent and leaves it without clear criteria to verify its efficiency.

History shows us that subsidies rarely appear in isolation. They almost always create imbalances, distortions and bad incentives in the market that are later used to justify new subsidies. According to reporting by the news platform *MegaWhat* on 19 March 2026, the government is already working to set up financing lines through the Brazilian Development Bank (BNDES) in order to postpone tariff increases that are already unsustainable, in some cases with double-digit adjustments. To a large extent, these increases are a consequence of the subsidies created in the past decade, which, in the last year alone, generated R$50 billion in the Energy Development Account (CDE).

What will happen when the new subsidy of the capacity-based expansion model comes knocking at the consumer's door with new tariff adjustments? We will have to push the debt forward once again, because we will still be paying the interest on the previous subsidy. The risk is that we create a subsidy pyramid. It is clear that this is not the way.

By postponing the harder discussion, the reform of market design from wholesale to retail, we opted for a "pragmatic" solution, a word that, when used in the power sector, should always raise suspicion. Therefore, before deciding to make capacity auctions the central axis of expansion, we must answer a simple question: are we, in fact, creating an efficient mechanism to contract the attributes the system needs (flexibility, capacity and energy), or are we merely resorting to the usual shortcut, the subsidy, to give a pragmatic answer that is known to be suboptimal?

Five Problems with Brazil's 2026 Capacity Reserve Auction

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ABSTRACT

Brazil's 2026 capacity reserve auction (LRCAP) marks a shift from availability contracts, which resemble call options, to capacity contracts that pay generators a fixed revenue without delivering energy to consumers. I argue that this shift is premature and creates five incentive problems. The first is an addiction to guaranteed revenue. Combined with source selection, the fixed payment works as a subsidy and sets off a race for new auctions, and 10- and 15-year terms lock consumers into crisis prices. The second is a market design unready for these contracts. Without a real-time market, two-settlement, or properly priced ancillary services, projects became viable almost entirely through the fixed revenue, at prices about 3.8 times those of the most expensive recent capacity auction held by PJM Interconnection in the United States. The third is demand set by institutions that fear a blackout far more than a diluted tariff increase. The fourth is a single buyer that passes costs through and turns commercial disputes into regulatory ones. The fifth is regulatory complacency. Markets fifteen years ahead of ours show that short-term price formation comes first. Before contracting capacity, prices must be allowed to tell the truth about the system's operation.

Given the discussions we have recently been seeing in the media, which often resemble a battle between good and evil, and which now seem to be escalating into a dispute between thermal plants, batteries, and renewables, it may be important to try to look at the problem from another angle. This text is not intended to make value judgments

about specific technologies. Generation sources should not be treated as villains or saviors, especially because none of them is free from negative externalities. More importantly, modern power systems should not view these technologies through a moral lens, but rather as a portfolio of physical, operational, and economic attributes that may be more or less useful depending on the system's needs at each moment.

This text is also not intended to argue about the legitimacy of the auction. We start here from the premise that the capacity reserve auction (LRCAP) has taken place and that society, and above all the sector, with all its successes and mistakes, has converged to where we are. The objective here is different: to discuss the structural problems associated with the design of the auction and with the very format of capacity contracts, topics that, in my opinion, are still receiving less attention than they should. The purpose is to raise questions that perhaps need to be at the top of the priority list before any new decision on capacity mechanisms in Brazil.

The LRCAP may be the most controversial contractual format the Brazilian power sector has ever decided to flirt with. This is not because reliability, flexibility, and resource adequacy are unnecessary. They are necessary. The central issue lies in the way chosen to remunerate these attributes and in the economic and institutional incentives that emerge from this contractual design.

In this context, the adoption of the LRCAP represents a particularly significant change for the Brazilian power sector. Over the past two decades, Brazil has built relatively sophisticated experience with forward contracts and structures similar to call options, such as the availability contracts used in the new-energy auctions, designed precisely to make investment viable. The migration toward capacity contracts therefore does not represent merely an incremental change of contractual product, but rather a profound alteration in the logic of remuneration, risk allocation, and coordination among the market, consumers, and sector institutions.

This is not only a risky move, but one that, given the current characteristics of the Brazilian market design, appears premature and inadequate. In the points that follow, I argue that the LRCAP introduces

at least five relevant problems of economic and institutional incentives that deserve to be discussed in much greater depth before this type of mechanism becomes structurally consolidated in the Brazilian power sector.

The first problem – addiction to guaranteed revenues and market reserves

The capacity contract creates a fixed revenue for the generator without transferring to the consumer any right to the energy produced. In other words, the consumer pays for availability but still buys the energy separately in the market. This is a poorly adapted legacy of the vertically integrated era, when competition and energy markets did not exist, later repackaged in the modern market as a kind of universal income for eligible generators, intended to close the remuneration gaps of the sector as a whole.

In practice, however, the combination of this concept (payment without delivery of energy) with the selection of specific sources works as a subsidy. The contracted generator competes in the energy market carrying an additional guaranteed revenue that other agents do not have, or at least should not have. In other words, we have chosen a format that deepens the sector's dependence on subsidies. Moreover, we adopted 10- and 15-year contracts, locking consumers into crisis prices, even though international experience shows that annual procurements, or contracts ranging from 1 to 3 years, offer greater flexibility and better price management, according to the Federal Energy Regulatory Commission (FERC).

The problem with this is that we foster a parallel market. The result is a race among the other agents for their own subsidy, their own capacity auction. We thus converge toward an informal market for subsidies and toward an environment in which economic viability is less and less coordinated by the signals of the energy market. It is like an addiction: once capacity contracts come into use and agents feel entitled to a guaranteed revenue, there is hardly any way back.

Opening procurement to all technologies and clearly specifying flexibility and capacity products (without overlap with the energy attribute, since capacity contracts do not remunerate energy) would make room for greater technological competition. This would reduce the system's exposure to gas turbine price shocks and create a much more efficient competitive dynamic for consumers and for the system itself. The role of the market and of its mechanisms, such as auctions, is to discover the winning technologies, not to determine them.

The second problem – the inadequacy of the Brazilian market design

Even if one accepts the legitimacy of capacity contracts, there is an important point that rarely appears in the Brazilian debate. In international markets where capacity mechanisms are used, these contracts usually play a complementary role. They are not designed to fully finance a project.

The generator knows that its revenue will come from multiple sources: the fixed revenue of the capacity contract, revenue from the short-term market (spot and forward contracts), ancillary services revenue, arbitrage, hedges, and other products that require adapting the generation profile to solve the system's problems.

In developed markets, which have ancillary services prices co-optimized with energy prices, two-settlement, and credible real-time prices granular enough to reflect the true opportunity cost of the network, competition and alternative revenue streams force agents to bid fixed revenues below the project's break-even in capacity auctions. In other words, the capacity contract serves only as a revenue complement and as a residual mechanism of system adequacy.

Brazil still operates without prices that adequately reflect several critical dimensions of operation. We do not have a real-time market, we do not have two-settlement, and ancillary services remain largely without adequate economic pricing.

In this context, where flexibility signals remain extremely distorted and out of step with what is known to matter in a system with high

renewable penetration, the alternative of future revenue practically disappears for developers. The natural result is that agents try to capture practically the entire economic viability of the project within the fixed revenue of the capacity contract.

This only reinforces that our regulatory environment is not yet prepared to accommodate capacity contracts. And, unfortunately, this is exactly what we saw in the 2026 LRCAP. Even compared with the most controversial and expensive capacity auction in the recent history of PJM Interconnection (PJM), in the United States (see Fig. 9 in FERC), Brazil's 2026 LRCAP reached values roughly 3.8 times higher.

The design of the 2026 LRCAP, combined with low competition, segmentation by source, and a regulatory environment and market design that do not adequately remunerate flexibility, culminated in a parallel market in which developers were able, in a perfectly rational response to the incentives and rules in place, to make practically all of their investments and costs viable through the fixed revenue of the capacity contract.

In other words, the incompatibility between the Brazilian regulatory environment and the format of capacity contracts meant that, instead of splitting costs between capacity and energy, we allocated practically 100% of the project's economic viability to capacity, ignoring the fact that the consumer will still have to pay in full for the energy, when it is produced, at the market price.

The third problem – the administrative definition of a demand for capacity

Notwithstanding the inadequacy of the current market design and its incentives for capacity contracts, there is another, even more delicate structural problem: the definition of the auction's demand itself. In more traditional markets, demand arises from consumers' real willingness to contract a given product at a given price. In capacity auctions, however, demand is defined institutionally by the sector's central bodies, involving mainly the system operator, the planner, and the government, through

the Ministry of Mines and Energy (MME). And this creates a natural upward bias.

For these institutions, the political and institutional costs of a supply crisis or a blackout are infinitely greater than the costs of a tariff increase diluted over many years. After all, tariff increases can be softened, spread out, or deferred over time. The recent debate on tariff deferral shows exactly this. It is much easier to manage a cost spread thinly across future tariffs than to deal with an explicit energy crisis.

Thus, when the counterparty that defines demand is not the same one that pays the bill directly, the economic incentive changes completely. The natural result is more conservative procurement, greater demand for capacity, and less economic pressure to reduce costs. This detail is central because it shows that the problem does not lie only on the supply side of the auction. It also lies in the way demand is constructed institutionally.

Furthermore, capacity mechanisms with administratively defined demand become particularly vulnerable to the exercise of market power when combined with low structural competition, high supply concentration, or excessive product segmentation. Under these conditions, the competitiveness of the auction tends to be reduced even further.

The fourth problem – the institutional incentives of a single buyer that passes costs through, and the distance from the real payer

There is also a deeper problem, arising from the institutional relationship between generators and the representative of the buyers. Contracts cease to be relationships between traditional buyers and sellers and become relationships between generators (sellers) and the Electric Energy Trading Chamber (CCEE) as the buyer, which acts as a single buyer and passes the cost directly through to tariffs.

In addition, in practice, the Brazilian Electricity Regulatory Agency (ANEEL) also plays an important role, for example in mediating conflicts, often issuing decisions that directly affect these relationships. The history of the 2021 auction shows this dynamic clearly.

The point is that both the CCEE and ANEEL are of a nature quite different from that of an economic buyer. And this is neither a demerit nor a problem per se. Both ANEEL and the CCEE are institutions of enormous relevance to the sector. In other words, the objective here is far from criticizing these two institutions, quite the opposite. The central point of the argument lies in the incentives that this type of relationship can generate.

Among the functions of the CCEE and the regulator are the mediation of conflicts, the guarantee of institutional stability, the prevention of crises, and the promotion of solutions. And, generally, they do this very well. But when we remove from the equation the counterparty that actually pays for and consumes the product and put in its place administrative entities with institutional roles of this nature, incentives change completely, and generators are the first to understand this new dynamic. In moments of operational difficulty, construction delays, supplier problems, or sector crises, the conversation ceases to be commercial and becomes regulatory, with a far from negligible dose of political interference.

The domestic and international track record shows exactly the same pattern: pressure to relax contract terms, postponement of obligations, requests for rebalancing, and successive renegotiations. After all, the counterparty is not a private buyer defending its cash; it is the regulator trying to avoid a systemic problem. For better or for worse, the case of the 2021 capacity contract offers fairly clear examples of this phenomenon; I leave it to the reader to draw their own conclusions.

It is worth recalling that, for more than two decades, we have calculated energy backing (lastro), allocated it to generators, and required all consumers to contract it. In principle, there is no structural reason why other attributes that one may wish to internalize and price in the market, such as flexibility, capacity, inertia, or emission level, would need to be contracted through a regulated single buyer with cost pass-through. But, without going into the merits of which attributes should or should not be created and contracted (great caution is needed here, because some of these attributes may be mere offshoots of others, such as flexibility, which can be understood as the ability to

vary the delivery of energy over time, something directly related to the granularity and accuracy with which energy prices are settled), the main point is simple: the counterparty matters. Its willingness to break contracts, switch suppliers, and respond to prices alters the incentives, the contractual discipline, and, ultimately, the very functioning of the market.

The fifth problem – the incentive toward regulatory complacency

An extremely important point that the reader needs to grasp is that the discussion of capacity mechanisms was placed ahead of the reform that really needed to come first. Therefore, before introducing additional administrative procurement mechanisms, perhaps we should answer a more fundamental question: which problems of the Brazilian power system could not effectively be solved by properly restructured price signals in the short-term market, complemented by more flexible and sophisticated energy contracts and by a connection to flexibility markets in the distribution companies?

No international market is necessarily better than ours, nor is any of them an example of great virtue. Many still use capacity contracts, carry heavy subsidy burdens, and are frequent targets of lobbying and political interference.

Notwithstanding, these markets are approximately 15 years ahead of us in adapting to a reality of high penetration of non-controllable resources. And, observing this evolution, including its failures, the consensus that emerges is that many problems are avoided when we first organize price formation in the short-term market, properly structuring real-time markets, ancillary services, the day-ahead market, and two-settlement mechanisms. When we create economic signals that are more faithful to operational reality (read more), all agents gain a minimally realistic reference for the value of flexibility.

Some examples are particularly interesting to mention. In the Electric Reliability Council of Texas (ERCOT), the Texas market in the United States, for example, batteries have displaced thermal plants on a large scale in the provision of frequency regulation services.

The attractiveness of this short-term product created such intense competition that the massive entry of batteries drove prices to historic lows. Thermal plants, for their part, did not lose their value. They began to compete in ancillary service products aimed at load restoration and in longer-duration services, where batteries face greater limitations. Hybridization of thermal plants and batteries is also not uncommon.

Notwithstanding, it is not the government or a sector entity that discovers the solution (and the technological arrangements that end up prevailing at any given moment), but competition. The solution emerges; it is not imposed. And, as a rule, it comes as a surprise.

This example reveals two important things. First, the value reference for each system attribute becomes much clearer when well-structured short-term markets are in operation. Second, thermal plants and batteries are at once complements and competitors, depending on the product, the time scale, and the operational need to be met.

Here, however, we tried to start from the end. We decided to implement capacity contracts without transparent and dynamic references for the value of flexibility and capacity, without adequate balancing mechanisms for surpluses and deficits, with market reserves by source, low competition, and a contractual design that has not only been criticized for years by the leading researchers in the field, but is also incompatible with a regulatory environment that has not yet managed to properly organize the basic economic signals of the short-term market.

The greater the gap between what prices are able to remunerate and what the system really needs, the greater the cost transferred to the regulated fixed revenue of the capacity contract tends to be. That is why discussing capacity contracts before deeply reforming price formation in Brazil (where we should also include retail and the distribution companies' flexibility market) means completely inverting the logic of priorities.

Thus, before contracting capacity, the sector must allow prices to tell the truth about the system's operation in its multiple dimensions. The sector needed modernization. It chose, however, to expand regulatory coordination before consolidating the market's fundamental economic signals.

The risk now is that the sense that the problem has been solved will settle over sector entities and public bodies, preventing important discussions on advances in market design. And soon we will be back discussing exactly the same problem.

The Power Sector and the Land of Lost Opportunities

Brazil, with everything it takes to be a global energy power, is compromising its competitive advantage through its own choices

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ABSTRACT

I argue that Brazil met a known flexibility problem late, with a single instrument, and wasted a rare window to modernize its regulatory design. In 2025 the National Electric System Operator (ONS) estimated a 96% probability of loss of load from insufficient capacity by 2029 and expected curtailment in 80% of daytime hours over five years. In March 2026, the capacity reserve auction (LRCAP) contracted 16.47 GW of thermal and 2.5 GW of hydro capacity for more than R$38.9 billion a year, 3.8 times the latest annual capacity price of PJM Interconnection in the United States. Restricting the auction to one technology limited supply when demand was known to be high, and prices came with almost no discount. Combined with a market reserve, the fixed revenue of these contracts works as a subsidy, and consumers still buy the energy at short-term prices. The deeper problem is the daytime surplus, much of it from distributed solar generation. Local flexibility markets with aggregators, real-time prices, and two-settlement would attack it at its origin. Relying only on capacity auctions gives up three futures: consumers investing in batteries, distributed generation as a paid flexibility asset, and a market that integrates wholesale and retail.

In 2024, the National Electric System Operator (ONS) was already pointing to a flexibility deficit, in the face of excess solar generation during the day and the sharp rise in net load in the late afternoon, a phenomenon known as the evening demand ramp. In 2025, the ONS deepened the diagnosis: it estimated at 96% the probability of loss of load due to insufficient capacity by 2029 and assessed that 80% of daytime hours will require curtailment over the next five years. In March 2026, we held the second capacity reserve auction (LRCAP), which contracted 16.47 GW of thermal capacity and 2.5 GW of hydro capacity, under a contract type that delivers no energy to the consumer.

Despite the undeniable need and the countless warnings from the ONS, the government chose to tackle the problem late and with a single mechanism, without attacking its root cause: the excess of distributed generation during the day. The result was a capacity payment, passed through via a charge, of more than R$38.9 billion a year (US$395,000/MW-year, 3.8 times the price of the latest annual auction of PJM Interconnection, in the United States, for 2026/27). Worse, the choice wasted a rare window to reorganize the outdated regulatory design and put it back on a positive path of modernity and efficiency.

In an auction, the price reflects the balance between supply and demand. Faced with a high demand for flexibility, which stems from the market's inability to reorganize itself to provide it, opening the auction to all technologies is the mechanism that squeezes the price by increasing competition. Hydro plants, thermal plants, batteries, and aggregated consumers share, to a greater or lesser degree, attributes such as flexibility, capacity, and energy. Closing a tender around a single technology means restricting supply in the face of demand known to be high.

The result was predictable: high prices, with almost no discount below a price cap that had been raised shortly before the auction. The global supply chain completes the picture: gas turbines face waiting lists of more than a year under pressure from data centers. On the other side, batteries are in oversupply, with falling prices. We pay dearly where the world market is tight and give up the surplus where it is plentiful.

The chosen format contains a second trap. Under the capacity contract, the generator receives a fixed revenue for availability without delivering in return the energy it produces, the only product for which everyone competes in the market. If we add to this the market reserve for a subgroup of agents, the fixed revenue in practice takes on the character of a subsidy. And the consumer? The consumer will still have to buy this energy in the short-term market, remaining exposed to rising fuel prices driven by global geopolitical crises.

The contrast with the availability contract, which structured the new-energy auctions for two decades and resembles a call option, is direct. Under it, the auction premium is the generator's only revenue and, when the thermal plant is called to produce, the energy belongs to the consumer, who settles it in the market and reimburses the generator for its variable cost, which limits the consumer's exposure to high prices in the short-term market.

But there is an even deeper problem. The sector does not really have an evening ramp problem; it has a daytime surplus problem. The net-load ramp, as the sun goes down, is one of the consequences, though not the only one, of the excess solar generation during the day that the system still cannot absorb efficiently. And this surplus materializes, to a large extent, inside the distribution network, in distributed solar generation. Attacking the ramp only through centralized thermal expansion is treating the symptom without touching the cause.

It is already clear that distributed generation (DG) will also be subject to curtailment. Less clear, however, is what will happen to DG once this curtailment is implemented, and to the consumer, when the costs of the LRCAP show up in tariffs and in short-term prices. The continuing fall in the investment cost (CAPEX) of batteries and DG, together with rising short-term prices, pushes consumers toward a wave of reduced dependence on the grid. The LRCAP thus tends to mitigate its own need, but, unfortunately, through a side effect that arrives after the investment has already been contracted. Forcing a complex problem, with strong couplings between low- and high-voltage assets, to be solved only by generators of a single type at high voltage is clearly suboptimal.

Solutions to problems that originate in distribution and propagate up to high voltage require integrated action between retail and wholesale, a path already taken in more developed markets. Local flexibility markets in the distribution companies, with aggregators coordinating generators, batteries, and consumers, combined with real-time price signals and two-settlement to value flexibility in a way that is agnostic to the source providing it, attack the problem at its origin.

Distributed flexibility can deliver greater reliability to consumers, mitigate reverse power flow and voltage violations in distribution, and also relieve the thermal and hydro ramp at sunset. Attacking the problem at its origin, and according to the system's needs, makes it possible to address the pain points of the distribution companies, the ONS, consumers, and DG itself, with a more efficient sharing of costs among agents rather than full pass-through to consumers. And for anyone who doubts how fast a market can grow in an environment squeezed by high prices, it is enough to recall DG between 2012 and 2024, which went from almost nothing to more than 30 GW, a level already surpassed by distributed batteries in the United States. When the regulatory soil is fertile, the market is born quickly and spreads.

Excess generation in distribution and the inability to absorb it at high voltage call for regulatory reform, not just more centralized generators. The exclusive focus on capacity auctions forgoes three futures: (1) that of the consumer who invests in batteries to increase their reliability, provide services to the grid, and reduce their bill; (2) that of DG, which evolves from part of the problem into a remunerated flexibility asset; and, finally, (3) that of a functioning market, with integrated wholesale and retail and local flexibility markets in the distribution companies balancing cost, reliability, and utilization in the last miles before the consumer. Worse, the capacity-auction solution may push us, late and in disorder, toward the very distributed architecture we chose to ignore, but only after we have paid the bill for both paths. This is how a country with everything it takes to be a global energy power compromises, through its own choices, its competitive advantage.

The Regulatory Barrier in Brazil's Power Sector and the Battery Auction

The battery auction exposes the lack of adequate price signals to remunerate flexibility and to let the market coordinate investment.

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ABSTRACT

The main barrier in Brazil's power sector is regulatory. The country has the resource, the technology, and the capital, but its prices do not tell the truth about scarcity. The consultation on the first battery auction, opened in July 2026, centers the debate on who will pay its charge. I argue that this is a false problem. The real problem is the decision to postpone the correction of wholesale and retail price signals. A competitive auction is not a market solution. It must answer administratively what agents facing coherent prices would answer easily: where batteries will be needed, how they will be operated, who benefits, who is harmed, and what price cap fits. Distribution, where solar generation causes overloads and reverse power flows, remains untouched. After the capacity reserve auction of March 2026, which contracted more than 16 gigawatts of thermal capacity at R$38.9 billion per year, Brazil is preparing to subsidize batteries instead of giving them incentives. Because the cause and the beneficiaries of storage are identifiable, a first step through the market is within reach. Two experiences show that agents respond to prices. In the 2001 rationing, consumers chose efficient appliances themselves. In Texas, competing batteries drove down ancillary-service prices. Price formation must come first.

The main barrier facing Brazil's power sector is neither technological nor economic: it is regulatory. We have the renewable resource, the technology, and the capital willing to finance it; what we lack is a market whose prices tell the truth about the system's scarcity, and the belief that markets work in electricity.

The public consultation opened on 30 July, on the tender documents for the country's first battery auction within the National Interconnected System, is the next chapter of this story. The debate it has already stirred centers on who will pay the charge arising from the centralized procurement of batteries, when the underlying question is a different one: why we are once again procuring centrally a service that, in a well-designed market, would have a willing buyer.

Law 15.269/2025 assigned the cost of the batteries exclusively to generators. Recently, however, the Brazilian Electricity Regulatory Agency (ANEEL) removed from the tender the allocation of the capacity reserve charge, deferring it to a separate regulatory process. The logic that prevailed in Congress is that whoever gives rise to a cost should bear it. Since the demand for flexibility and capacity arises from non-controllable renewable generation, it would fall to those generators, and not to consumers, to finance the batteries, which would also help reduce curtailment (the cutting back of renewable output).

The principle is reasonable, but the instrument chosen is not effective. This is because a competitive contest in an auction is not the same as a market solution. An auction may be hotly disputed and still procure administratively, in excess or in shortfall, what a well-organized market would reveal on its own and allocate voluntarily to the beneficiaries willing to pay.

Capacity auctions struggle to answer administratively the questions that agents, in a market whose prices are consistent with the reality of the system, would answer far more easily: (1) where will the demand for batteries be located over the next 10 years in Brazil, and to what extent would it replace or complement the demand for the thermal plants contracted in the first auction? (2) How will the batteries be operated, and for whose benefit? (3) Will their costs be allocated in full to their beneficiaries? (4) Who will be harmed by the arbitrary choices that will

be made in this process, so little discussed? (5) Which services will be included, and what price cap is compatible with them?

Moreover, the problem remains practically untouched at the distribution level, where photovoltaic generation is now concentrated. These sources not only aggravate the challenges already present on the high-voltage grid, but also cause, at low voltage, overloads, reverse power flows, and various other operational problems that require billions of reais of additional investment in distribution infrastructure.

In more mature markets, the response to this problem came, for the most part, through the market. As prices came to reflect the value of flexibility, batteries ceased to be an accessory and became part of the business model of many renewable projects. On the demand side, consumers of every size, including data centers that use their generators and batteries to provide services to the grid, monetize the flexibility of their consumption in different markets, through short-, medium-, and long-term contracts, all anchored in short-term prices.

So if the cause and the beneficiaries are known, there is no reason not to organize a first step through the market, in which the beneficiaries of the service, according to their willingness to pay, contract the suppliers who, according to their willingness to supply, reach an equilibrium price for that attribute or piece of equipment. Under such a design, the shortage of capacity and flexibility would be resolved, to a large extent, as a byproduct of private decisions coordinated by market incentives, without any need to define by regulation who must pay.

That is why the debate over who will pay the battery-auction charge is, at bottom, a false problem. The real problem is the decision to postpone the correction of price signals, in the wholesale and in the retail markets, even though everyone recognizes that they are at the origin of a large share of these distortions.

Some form of initial economic incentive, with a defined end date and treated as a public policy financed by the federal budget, could even be considered to ease the establishment of the local supply chain. Never, however, interfering with the structure of the relationship between buyers and sellers, as capacity auctions do, nor with the energy tariff, which affects every other sector of the economy.

Nonetheless, it is precisely the inability of the sector's institutions to bring about the correction of these price signals that makes it impossible to remunerate properly those who provide flexibility. As a consequence, "pragmatic" solutions outside the market design, such as capacity auctions, gain ground.

After the capacity reserve auction that, in March of this year, contracted more than 16 GW of thermal capacity at a cost of R$38.9 billion per year, under contracts of 10 to 15 years (prices more than three times those of the last capacity auction held by PJM Interconnection, in the United States, whose pricing had already caused a considerable uproar), we have begun preparing to subsidize batteries rather than to give them incentives.

We thus continue subsidizing specific technologies, without integrated planning or market coordination, to solve a problem created by the absence of price signals and by subsidies to renewables that have not yet been fully removed. It is a vicious cycle that produces new distortions, and tariffs so high for final consumers that they must be paid in installments at compound interest.

International experience is available: countries fifteen years ahead of us have already worked through the trials and errors we could learn from. One important lesson is that the order matters. First, fix price formation; then, create the incentives for the beneficiaries themselves to buy the batteries, building the market environment and the mechanisms they need in order to respond to price signals that track operating reality. Precisely because, in the case of storage, the cause and the beneficiaries are identifiable, this first step through the market is within our reach.

The 2001 rationing is rich in examples. We did not carry out a centralized, compulsory purchase of more efficient white-goods appliances, with the cost passed through to the energy tariff, in order to reduce consumption. Instead, the government strengthened the National Electricity Conservation Program (Procel) and energy labeling and, above all, passed the Energy Efficiency Law (Law 10.295/2001), which set minimum efficiency levels for equipment sold in the country. There was a subsidy, but in the form of temporary incentives to the domestic manufacturing base.

In the end, however, it was the consumers themselves who decided to invest in more efficient equipment, so as to avoid the tariff surcharge applied to those who failed to meet the reduction target during the rationing. Thus, contrary to what many claim, Brazilian consumers proved fully capable of making the right choices in what was, perhaps, the largest demand-response program in history.

In the Electric Reliability Council of Texas (ERCOT), the operator that serves Texas, in the United States, fierce competition among batteries drove down the price of several very-short-term ancillary services and displaced thermal plants toward other services of longer duration. The lesson of the two experiences is the same: all agents respond to price incentives with enormous effectiveness, solving the system's problem efficiently when the price is well defined. The market works. What it asks of us is the decision to want the best for the consumer and for all agents that prove efficient.

Chapter 8

A Myopic and Incomplete Price System

2026

In this chapter

The Confusion over Prices and Risk Aversion in the Power Sector 128
From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System 133

Introduction

Short-term prices were again the subject of an intense debate in the first months of 2026. For some, they were too high because the official models had raised their risk aversion too much. For others, prices had been kept low for a long time by several biases, and the higher risk aversion corrected them. I argued that both sides were piling problems of different natures onto a single instrument. By June the dispute had moved to curtailment, the cuts in renewable output ordered by the operator. The question was whether run-of-river hydro plants should share those cuts with solar and wind farms. In the two articles of this chapter I read both disputes as symptoms of one cause. The price system is myopic, because it does not represent the network, real time, or reserves. It is also incomplete, because it does not pay for the services that have become critical to the security of the system.

In April I started with the way risk is measured. The official models express risk aversion through a nested conditional value-at-risk applied to total operating cost over a horizon assumed to be infinite. This metric is built on a cost that no one pays or receives, discounted at an interest rate disconnected from the sector. No system operator in the world uses it. Its parameters are calibrated for one initial condition and lose validity as the system evolves. Absolute alternatives were available. One is the risk-aversion surface, which sets a minimum storage level for a given time of the year. Another is a limit on the risk of energy deficit. The dual variables of these constraints measure the cost of violating them, and they would price that risk in every state of the system. The confusion grows because inflow forecasts have an optimistic bias and the risk parameters are calibrated on simulations affected by the same bias. Any price level becomes contestable, and the operator drifts away from its own models. The good news is that the National Electric System Operator has taken responsibility for the models.

In June I took the image for the second article from Bruegel's painting *The Blind Leading the Blind*. When signals are myopic, even perfectly rational agents walk toward inefficient decisions. Curtailment is a dispatch decision, but no price reflects it, because the network is absent

from the formation of the spot price. The spot price is the short-term price that settles each deviation from a contract. The floor on the spot price patches another distortion, the zero variable cost assigned to hydro plants in the price-formation models. Removing the floor alone would be unfair to hydro plants, which reduce output at midday, ramp up at sunset, and absorb fluctuations within seconds without explicit payment. I proposed three measures. The first is real-time prices updated every ten minutes, preferably at each node of the network. The second is two-settlement, in which deviations from the positions scheduled in the day-ahead market are settled at real-time prices. The third is joint markets for energy and operating reserves. The first two steps require offers of both price and quantity, starting with renewables and later extended to all agents. The transfer of the models to the operator makes this feasible.

The reform must also reach retail. The operator's demand-response program should evolve into a distributed-flexibility program that includes loads, distributed generation, and batteries. Non-wires alternatives should become a permanent planning tool. They let a distribution company contract distributed flexibility instead of reinforcing its network. Aggregators and retail suppliers would then close the loop between wholesale and retail. Without this reform, low prices are an illusion. Scarcity costs reappear in capacity auctions, out-of-merit-order dispatch, reserve auctions, and sector charges, where they no longer show who should invest, operate, or be paid.

Core ideas

1. The 2026 debate on the level of short-term prices loads problems of different natures onto a single instrument, the risk-aversion parameters.
2. Nested conditional value-at-risk on total operating cost has no parallel among the world's operators and no absolute reference. Criteria based on minimum storage or deficit risk were available.

3 An optimistic bias in inflow forecasts, combined with calibration on biased simulations, keeps the sector in permanent confusion and pushes the operator away from its own models.

4 Curtailment disputes are a symptom of payments detached from the services actually provided, since price formation does not represent the network.

5 The spot-price floor patches the zero variable cost assigned to hydro plants, whose flexibility services go unpaid.

6 Three measures would correct the design: ten-minute real-time prices, preferably nodal; two-settlement against the day-ahead schedule; and joint markets for energy and reserves.

7 Demand response, distributed flexibility, non-wires alternatives, aggregators, and retail suppliers are components of one market design that links wholesale and retail.

8 Low prices are an illusion, because scarcity costs reappear in auctions, out-of-merit-order dispatch, and charges, where they no longer signal who should invest.

Conclusions

The controversies of 2026 over price levels and curtailment are what a myopic and incomplete price system produces. Its models measure risk without an absolute reference, its prices ignore the network and real time, and the services that keep the system secure have no price. The technical solutions exist, and the operator is now responsible for the models. What is missing is coherence, leadership, and the decision to implement those solutions.

The articles

The Confusion over Prices and Risk Aversion in the Power Sector, on LinkedIn on 24 April 2026, examines the risk metric of the official models and its interaction with the optimistic bias of inflow forecasts. *From*

Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System, on LinkedIn on 25 June 2026, takes the argument from curtailment to retail and proposes the three measures of a structural reform of market design.

The Confusion over Prices and Risk Aversion in the Power Sector

Original title: *A confusão dos preços e aversão a risco no setor elétrico*
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ABSTRACT

The Brazilian power sector is once again debating the level of short-term prices. Some see them as too high because of exaggerated risk aversion, others as a correction of prices kept low by biases. I argue that the debate loads distinct problems onto a single instrument. The deeper problem is the risk metric itself. We chose a nested conditional value-at-risk on total operating cost over an infinite horizon, a metric without parallel among the world's operators. It rests on a cost no one pays or receives and on a discount rate detached from the sector. Parameters calibrated for one initial condition lose validity as the system evolves. Absolute alternatives were available, such as the risk-aversion surface on minimum storage or a limit on the conditional value-at-risk of the energy deficit. Their dual variables price that risk in every state of the system. The problem grows because inflow forecasts carry an optimistic bias, and the parameters are calibrated on these biased simulations. Any price level becomes contestable, and the operator drifts away from its own models. The operator's decision to take over the models is good news. The sector lacks coherence and leadership. Without them, the outcome will be institutional fragility, litigation and a bill passed on to consumers.

In recent months, the power sector has once again been intensely debating the level of short-term prices. For some, they are excessively high, reflecting an exaggerated risk aversion; for others, the price was low for a long time because of several biases that affect the problem, and the recent increase in risk aversion came precisely to correct them. The

point is that this discussion ends up piling several problems of different natures onto a single instrument when, in fact, each one should be treated separately, following the techniques and principles appropriate to solve it.

At the center of this debate lies one of the great sources of friction: the change in the risk-aversion parameters. But there is a deeper issue: the metric used to account for risk aversion is part of the problem. When aversion is defined by indirect criteria and has no absolute references, an inevitable space opens up for conflicting interpretations. After all, everyone has their own risk aversion. Without an objective reference that clearly connects the security of the system with the language and references of operating a hydrothermal system, it becomes impossible to establish what an adequate risk profile actually is. In this scenario, the debate then becomes like the one we are witnessing, less technical and more interpretive. And that is exactly where the confusion begins.

Over the last decade, we had a broad and qualified discussion in the sector about the computational models of the power system. There were technically sound alternatives. The risk-aversion surface (SAR), for example, set a clear and absolute reference relative to the state of the system and, above all, in the language in which the operator is used to monitoring supply risk: a minimum storage level at a given time of the year. It is a criterion built on a non-relative reference, which can be computed with a low degree of ambiguity compared with the current methodology. This makes the discussion about the tolerable risk limit independent of the situation the system is in. Proposals such as a limit on the conditional value-at-risk (CVaR) of the energy deficit, another objective, transparent and easily understood metric, were also under discussion.

But we chose another path. We chose a metric that has no parallel in any system operator in the world: nested CVaR applied to the total operating cost over a horizon assumed to be infinite. We created a measure based on something that no one pays or receives, that has no practical and absolute reference for assessing risk, and that depends on a concatenation of monthly costs discounted at an interest rate disconnected from the reality of the power sector. The result is a highly

subjective construction and, therefore, one fundamentally open to every kind of challenge.

The current procedure to calibrate the risk-aversion parameters of the nested CVaR on cost seeks, through simulations that bear little resemblance to the real operation, to adjust operating metrics, such as the deficit and storage, to levels considered acceptable. The problem is that, once pairs of risk-aversion parameters (the λ and α of the CVaR) that seem "adequate" are defined, that validity is restricted to the initial condition and to all the other assumptions under which the simulation was performed. As the state of the system evolves, nothing guarantees that these same parameters will produce reasonable results. In fact, it is guaranteed that they will not produce the expected results, because the "price" of the penalty (or the λ of the CVaR) would need to increase to guarantee the same storage level deemed safe as we approach it. By contrast, an absolute and direct constraint on the storage level, for example, would produce exactly this effect; one need only analyze the dual variable associated with that constraint (whether from the SAR or from a constraint on the deficit), which precisely measures the opportunity cost of violating it in each state of the system, endogenously (by marginal substitution of the expected cost). This information is internalized in the primal decisions of a model that considers risk constraints.

The consequence is inevitable. By expressing risk aversion on cost, without an objective reference for what constitutes a risk event for the operator, we introduce structural subjectivity into the model. This approach may even be useful for private agents, who need to evaluate different risk profiles in their portfolios, but it is not suitable for operating a power system. Operators anywhere in the world work with direct security metrics, such as the probability of deficit and minimum storage levels. The question, therefore, is simple: why not optimize directly on the basis of these metrics?

By choosing nested CVaR on cost, we have once again missed the opportunity to move toward coherence. The current discussions reveal this issue, since no one is able, or has the right, to state how much of an increase in the spot price (PLD) is a fair trade for a higher storage

level in the Southeast "big bucket" at the end of N months. But we can all agree that taking the reservoirs below x% represents a structural risk. Obviously, every risk metric contains some degree of subjectivity; the SAR and the deficit risk are not free of it. Still, the conversation gains much more quality when we deal with absolute and direct references, based on the variables the operator effectively masters, whether in terms of supply risk or in terms of preventive and corrective actions.

If this subjectivity would already be problematic on its own, it becomes even more serious when combined with another well-documented factor: the optimistic bias in inflow forecasts. This bias, of relevant magnitude, leads the models to drain the reservoirs systematically, as discussed in several recent studies by the Laboratory of Applied Mathematical Programming and Statistics (LAMPS) at PUC-Rio.

The result is an environment of permanent confusion. Instead of attacking the causes of the problems, we systematically opt for indirect and pragmatic solutions, in the worst sense of the word. We increase risk aversion on cost, already highly subjective, to offset the effects of a bias we do not correct. We thus mix two distortions: a poorly defined risk metric and a systematic error in the system's main input.

Most worrying of all is that we calibrate the risk-aversion parameters on the basis of these same biased simulations. In this scenario, any result can be questioned. If prices rise, it is argued that risk aversion was artificially raised to compensate for known problems, such as the hydrological bias, the simplification of the network or the inadequate discount rate. If prices fall, the explanation is the opposite: the optimistic bias leads the model to see an abundance of resources that does not exist.

Today we live exactly at the intersection of these two inconsistencies: an operation model that measures risk indirectly and a streamflow forecasting model that distorts the simulations used to calibrate risk aversion. In this context, the level of mistrust and confusion we observe in the sector's discussions should surprise no one.

Perhaps the most worrying point is that we keep insisting on solutions ever further removed from operating practice. And every time we move price models away from operational reality, prices stop telling us the

truth about what the system really needs or has in excess. An additional effect is that the operator itself begins to distance itself from the models, since it must act differently from what they indicate in order to guarantee, in practice, the security of the system.

Notwithstanding, I do not believe that changing the risk aversion will solve our problem. It is only one of the relevant points for improving the coherence of the models and, consequently, the health of the sector as a whole. We need to face several problems swept under the rug over the years, such as, for example, the enormous bias in streamflow forecasting that results from the mismatch between the model and the dynamics of the series. While the world advanced in modeling short-term uncertainty, dynamic reserves, network constraints and multiple uses of water, we remained stuck in the 1990s discussing the technique of dynamic programming. Not that it is unimportant, but we forgot that it is not the end but the means to solve a real-world problem. The good news came recently, with the National Electric System Operator (ONS) taking on responsibility for the models. Congratulations on the initiative and the courage of everyone involved. Consumers and agents will soon be grateful if this initiative materializes.

What we lack is something simple: coherence and leadership. The rest, the sector has in abundance. As long as we do not align the model's risk aversion with absolute references, anchored in classic operational-security variables, and as long as we do not effectively monitor and reduce the enormous gap between the problem described in the models and the problem faced in real operation, the outcome will be inevitable: institutional fragility, litigation and the bill passed on to the consumer.

From Curtailment to High Retail Prices: The Problem Lies in a Myopic and Incomplete Price System

Original title: *Do curtailment aos altos preços no varejo: o problema está no sistema de preços míope e incompleto*

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ABSTRACT

I argue that no debate in the Brazilian power sector will be settled until prices pay for the services that have become critical to the system's security. As in Bruegel's painting of the blind leading the blind, myopic prices lead even rational agents to inefficient decisions. The dispute over which plants share curtailment shows the pattern, because payments remain detached from the services actually provided. Curtailment is a dispatch decision that prices ignore, because they do not represent the network. The spot-price floor offsets another distortion, the zero variable cost assigned to hydro plants, whose flexibility services are not explicitly paid. I propose three measures: real-time prices every ten minutes, preferably nodal; two-settlement against the day-ahead schedule; and joint markets for energy and reserves, with price-and-quantity offers starting with renewables. The recent transfer of the models to the system operator makes this feasible. The reform must also reach retail, turning demand response into distributed flexibility and non-wires alternatives into a permanent planning tool. Low prices are an illusion, because scarcity costs reappear in capacity auctions, out-of-merit-order dispatch, and charges, where they no longer signal who should invest. Technical solutions exist, and what is missing is the decision to implement them.

Without a reform of the price system to remunerate the services that have become increasingly critical to the security and functioning of the power

system, no debate in the sector will truly settle anything. We will keep debating symptoms while ignoring the cause. **In Bruegel's parable (the painting *The Blind Leading the Blind*, by Pieter Bruegel the Elder, 1568), a blind man leads other blind men. In the Brazilian power sector, the guide is a price system that no longer sees the physical and economic reality of the operation. And when the signals are myopic, even perfectly rational agents walk toward inefficient decisions. This is the tragedy of the power sector we are living through.**

Take curtailment as an example. The current debate is whether run-of-river hydro plants should or should not belong to the same curtailment-sharing group as solar and wind plants. There will be countless technical and regulatory arguments on both sides. The problem is that, regardless of who "wins" this debate, we will only be creating new problems. The reason is simple: as long as payments and receipts remain dissociated from the services actually provided, new conflicts of incentives will inevitably arise.

There is no point in creating rules to mitigate the effects without correcting the cause of the problem. Bringing prices closer to operational reality is what promotes allocative fairness. The debate on curtailment groups, for example, would be much simpler if agents could offer their own prices. In that case, we would know the true opportunity cost of each resource.

But that would require eliminating the floor on the spot price (PLD) so that each agent could express its true opportunity cost, now also relevant to determining which resources should be reduced or switched off (curtailed, or left unused because of real constraints that, at bottom, are economic but not explicit). It is worth noting that curtailment is nothing more than a dispatch decision for non-controllable sources imposed by operating constraints. Unlike the dispatch of controllable sources, however, this decision is still not supported by a price system that internalizes the constraints that produced it.

For example, in forming the PLD we do not represent the network, which to a large extent produces the "non-dispatch" of renewables. Without it, curtailment (of any source) will continue to be treated

as an administrative intervention subject to compensation, when it could be the result of economic and transparent decisions, which would also send the right signal to the right agents. Until we get our hands dirty and spend time and political capital to internalize in prices the operating measures we take absolutely every day, there will always be good arguments for either side of the debate.

There is, however, a concrete opportunity to move forward. The recent transfer of the governance of the computational models to the National Electric System Operator (ONS) creates the institutional and technical conditions to incorporate these representations gradually, provided that this process is followed and encouraged by the Electric Energy Trading Chamber (CCEE), the Brazilian Electricity Regulatory Agency (ANEEL), the Brazilian Energy Planning Agency (EPE), and the Ministry of Mines and Energy (MME).

Returning to the spot-price floor, the problem is that it was conceived precisely to compensate for another distortion. In the price-formation models, the variable cost of hydro plants is artificially set to zero, even though they have significant operation and maintenance costs. This is yet another classic example of a rule created to treat the effects, and not the cause, which ends up making new problems harder to solve.

Simply eliminating the spot-price floor would therefore also be unfair to hydro plants. Beyond their (immediate) operating costs, they continuously provide flexibility services that are fundamental to the system. They are the ones that reduce generation at midday to accommodate solar output, rapidly increase their output at sunset to offset both the drop in photovoltaic generation and the rise in demand, and absorb, within seconds or milliseconds, the fluctuations of load and renewable sources, keeping the power system in balance. These services have enormous economic value (for the system and for renewables), but today they are not remunerated explicitly and coherently.

How can we correct this injustice and, at the same time, make debates such as the one on curtailment much more objective? The answer lies in a structural reform of the market design with three basic measures: (1) real-time prices updated every ten minutes (preferably at each node

of the network), as in countries with a high share of renewable sources (with technology already available in the software used by system operators); (2) two-settlement against the positions scheduled in the day-ahead market, which also need to become more realistic; and (3) joint markets for energy and operating reserves, explicitly remunerating the ancillary services provided by controllable sources. It is important to stress that steps (1) and (2) require price-and-quantity offers from agents (not quantity alone; otherwise, the operator will still be unable to tell wind, solar, and run-of-river hydro plants apart), initially limited to renewables. Once the model is consolidated, offers should be extended to all agents, drawing on the experience of steps (1) to (3).

By remunerating each resource for the services actually provided, at the hours and places where they were needed, disputes cease to be predominantly regulatory and come to be resolved by the economic signals themselves. Moreover, this creates a powerful incentive for every technology to invest in controllability, whether through batteries or other storage solutions, demand flexibility, or even the purchase of stakes in, or contracts with, complementary agents. The free market finds and reveals the solution if prices tell the truth about the reality of the system and if there is market security for trades to take place safely.

This reform is also the key to a healthy opening of the retail market. Market opening has the potential to generate permanent benefits for consumers and to increase competitive pressure on prices, provided that consumers can respond to price signals through aggregators and retail suppliers. Read more in the article "The Power Sector and the Land of Lost Opportunities" (*O setor elétrico e o país das oportunidades perdidas*), Valor Econômico.

For that, however, these agents need to see coherent economic signals in the wholesale market, reflecting the system's real operating needs. But this alone is not enough. Demand response must be fully incorporated into the market design. The operator's demand-response program must evolve to encompass, in an integrated way, loads, distributed generation, batteries, and other aggregated distributed energy resources, effectively becoming a distributed-flexibility program.

This evolution must be accompanied by a new regulatory approach for distribution companies. The regulation of non-wires alternatives needs to stop being an exception and become a permanent instrument for planning network expansion. Whenever it is economically more efficient, distribution companies should be able to contract distributed flexibility as an alternative to conventional network reinforcement. This will make it possible to increase system reliability, postpone or avoid investments in assets with low utilization over their useful life, and significantly reduce the time needed to resolve electrical constraints. All of this reduces the network cost to be passed on to consumers.

In practice, demand response, distributed flexibility, non-wires alternatives, aggregators, and retail suppliers are not independent agendas. They are different components of one and the same market design. The economic signals produced in the wholesale market must travel the whole chain down to the final consumer and, in the opposite direction, the flexibility available in retail must be able to return to the system as an economic resource capable of competing, with its advantages and limitations, with the other system resources.

Only by closing this loop between wholesale and retail will aggregators and retail suppliers have the right incentives to coordinate and remunerate millions of small decisions on consumption, storage, distributed generation, and the offer of flexibility. The result is a more efficient, more reliable system with lower total costs, reducing the need for charges, cross-subsidies, and investments that could be avoided through adequate economic signals.

It is an illusion to believe that we have, or will have, low prices. If we look at the marginal costs calculated by DESSEM, the day-ahead scheduling model, we will see that, in moments of scarcity, the resources actually used have very high costs (see this post). The difference is that these prices do not appear where and when they should. Instead of remunerating scarce resources only at the moment and place in which they provide the service (as in a market with nodal and real-time prices), these costs end up being transferred to administrative mechanisms, such as the capacity reserve auction (LRCAP), out-of-merit-order dispatch, reserve auctions, and various sector charges. The cost still exists, but it

no longer correctly signals who should invest, who should operate, and who should be remunerated.

The result is perverse. Consumers keep paying for reliability and flexibility services, but they pay through charges, cross-subsidies, and administrative mechanisms instead of transparent prices. See, in the article on the problems of the LRCAP, the many problems we face when we choose to reinforce the path of capacity auctions instead of the market. At the same time, the agents that actually provide these services are often not remunerated in proportion to the value they deliver to the system, while those who could invest to expand this capability do not receive the right incentives to do so (see the discussion in this article on prices and their incentives).

In other words, we keep trying to solve remuneration problems by creating administrative rules, when we should allow markets themselves to price the different services that are now essential to operating an increasingly renewable power system.

The sector's greatest contradiction is that it already remunerates agents through a market, yet insists on preventing that market from fulfilling its main function: revealing the economic value of energy, flexibility, and reliability for the operation. This breaks the positive feedback loop between the revelation of costs, the operation, and incentives. Instead of improving price signals, we multiply exceptions, subsidies, charges, and compensatory mechanisms. We spend an enormous regulatory effort managing the consequences of an inadequate design, when practically everyone already knows the direction of the solution: making prices reflect, as faithfully as possible, the physical and economic reality of the system's operation. A post with numerical examples and a discussion at the event held by MegaWhat (which, incidentally, has been doing an excellent service to the sector and to society with these events, podcasts, and its very high-quality material) can be found in this post.

As long as we insist on correcting the symptoms instead of the cause, each new rule will solve an immediate problem but will create the conditions for the next regulatory distortion. There is no shortage of technical solutions. What is missing is the decision to implement them.

Chapter 9

Institutions, the Consumer and Justice

2026

In this chapter

The Two Absurdities about Itaipu 144
Electricity Reform as Social Justice 148
The Institutional Deterioration of the Brazilian Electricity Sector 152

Introduction

Itaipu's construction debt was fully repaid in 2023. Under the treaty that Brazil and Paraguay signed about half a century earlier, the tariff should then have fallen to about US$9/kW-month, returning the investment to society as a structural reduction in the price of energy. It stands instead at US$19.28/kW-month, roughly double, because so-called socio-environmental expenses grew sharply from 2022 and took the place of debt service. In March 2026 I described the treaty as something close to a fixed-income contract for the consumers of the future, an "energy pension". The two governments, the "owners of the fund", seem to have changed their minds in the very first year the benefit was due. This is the first of the two absurdities about Itaipu. In the articles of this chapter I move from prices to the institutions and rules that decide whether prices can tell the truth, and to the consumer who pays when they cannot.

Annex C of the Itaipu Treaty allows only strictly operating costs to be passed through to the tariff. The new spending bears no relation to the plant's location or to the expenses the treaty foresees. It lets both governments fund public policies, largely with an electoral bias, from the consumer's pocket and outside the scrutiny of the federal budget. Paraguay's claim that the plant owes it a "historical debt" is the second absurdity. As Jerson Kelman showed, citing Claudio Sales, Paraguay obtained a positive result of around US$6 billion from Itaipu, while Brazil accumulated a negative result of about US$90 billion. The problem is legal and ethical. Its cost goes beyond the money, because limited institutional maturity brings legal uncertainty, hidden cross-subsidies, risk premiums, and a loss of confidence in future treaties.

In June I argued that electricity reform has become a matter of social justice. The consumer is the reason the sector exists, yet the regulatory apparatus treated the consumer as a passive agent represented by third parties. Institutions therefore developed almost entirely from the perspective of generation, and market power came to be exercised in the regulatory layer above the market. Over time, protection became a regulatory prison, and the growth of distributed generation shows consumers escaping through its loopholes. This arrangement has

reached its limit. There is no room left for individual subsidies. It is also unfair that a regulation that does not evolve keeps consumers, renewable generators, and batteries from offering flexibility and ancillary services with technologies that already exist. Brazil is a stroke of the pen away from those technologies. In Texas and California, specific programs let consumers, aggregators, batteries, and hybrid arrangements take part in the market regardless of technology. The optimal mix then emerges from the resources and opportunities of each region.

Days later I described the institutional deterioration behind these problems. In mature markets, auctions and other market mechanisms exist to discover the winning technologies through competition for the lowest price, so they focus on the product whatever its source. Where a two-settlement system operates, agents trade 24 hourly contracts for the following day, and a real-time market settles the deviations in intervals of a few minutes. Under such prices, renewable plants rarely enter the market without batteries. Brazil has restricted competition by technology in practically every new-energy auction since 2005 and has discussed a reform of market design for more than a decade. Neither stems from a lack of technical knowledge. Both reflect institutions that are losing the capacity to plan, regulate, and carry out reforms. Neglected budgets at the Brazilian Energy Planning Agency and the Brazilian Electricity Regulatory Agency, and tensions between the ministry and the regulator, are the clearest symptoms.

Core ideas

1. The Itaipu Treaty worked as an energy pension for future consumers, and once the debt was repaid in 2023 the tariff should have fallen to about US$9/kW-month, but it stands at US$19.28/kW-month.
2. The socio-environmental spending that replaced debt service funds public policies from the consumer's pocket outside the federal budget, a problem that is legal and ethical.

3 Limited institutional maturity costs more than money, because it brings legal uncertainty, hidden cross-subsidies, risk premiums, and a loss of confidence in future treaties.

4 The consumer is the reason the sector exists, yet institutions developed from the perspective of generation and market power came to be exercised in the regulatory layer above the market.

5 Protection became a regulatory prison, and keeping consumers, renewables, and batteries from offering flexibility with available technologies has become a question of social justice.

6 Auctions and markets exist to discover winning technologies through competition, yet Brazil has restricted competition by technology in practically every new-energy auction since 2005.

7 Neglected budgets at the planning agency and the regulator, and tensions between the ministry and the regulator, reveal institutions that are losing the capacity to reform, and at bottom the problem is one of leadership.

Conclusions

In these three articles I locate the root of the sector's problems in its institutions. Itaipu shows what it costs when governments depart from rules agreed with consumers. The case for reform as social justice shows the price of keeping the consumer passive. The deterioration of the sector's institutions explains why a reform discussed for more than a decade has not happened. At bottom, as I wrote in July 2026, the problem is one of leadership.

The articles

The Two Absurdities about Itaipu, published by MegaWhat on 20 March 2026, is the only article in the book about Itaipu, and it treats the tariff as a test of institutional maturity and a way of funding public policies outside the federal budget. *Electricity Reform as Social Justice*, in Brazil

Journal on 26 June 2026, places the consumer at the center of the reform. *The Institutional Deterioration of the Brazilian Electricity Sector*, in CNN Brasil on 2 July 2026, written amid the dispute over the capacity auction, attributes the sector's impasses to the weakening of its institutions and to a lack of leadership.

The Two Absurdities about Itaipu

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ABSTRACT

I argue that two absurdities dominate the discussion of the Itaipu tariff. About 52 years ago, Brazil and Paraguay signed something close to a fixed-income contract for future consumers, an energy pension. Annex C of the Itaipu Treaty allows only strictly operating costs to be passed through, so the tariff should fall once the debt was repaid. That moment came in 2023. Yet so-called socio-environmental expenses grew sharply from 2022, unrelated to the location or to the spending the Treaty foresees. The tariff, which should be close to US$9/kW-month, stands at US$19.28/kW-month, roughly double. This new expense replaces debt service and lets both governments fund public policies, largely electoral, from the consumer's pocket and outside the scrutiny of the federal budget. The second absurdity is the Paraguayan claim that the plant owes the country a "historical debt". Quoting Claudio Sales, Jerson Kelman shows that Paraguay obtained a positive result of around US$6 billion, while Brazil accumulated a negative result of about US$90 billion. The 2024 operating agreement deepened these asymmetries against the Brazilian consumer. The problem is legal and ethical. It reveals the cost of limited institutional maturity, which brings legal uncertainty, hidden cross-subsidies, risk premiums and a loss of confidence in future treaties.

There are two central absurdities in the whole discussion about the Itaipu tariff that need to be stated clearly and directly. The first is that, about 52 years ago, Brazil and Paraguay signed something very similar to a fixed-income contract for the consumer of the future, an energy pension. Yet precisely in the first year in which the benefit would begin to be

paid, both countries, the "owners of the fund", seem to have changed their minds.

The objective was, and still is, crystal clear: to make possible the construction of a giant power plant to exploit the region's extraordinary hydro potential and, once the debt was paid off, to return this investment to society in the form of a structural reduction in the energy tariff. That moment came in 2023. Everything has been written, labeled, agreed and detailed for more than half a century in Annex C of the Itaipu Treaty, which is explicit in allowing only the pass-through of strictly operating costs.

What we saw, however, was the violation of the original idea and values of the Treaty, which should have been strictly honored by its managers and by the executive branches, leaving the National Congress only the constitutional prerogative of eventually revising it in cases of burdensome charges.

Unfortunately, none of this was done. From 2022, when debt service began to fall, and then in 2023, when the debt was fully repaid, there was a dizzying growth in so-called socio-environmental expenses, unrelated to the location or to the type of spending provided for in the Treaty. As a result, the tariff, which should be close to US$9/kW-month, benefiting consumers in both countries as the Treaty provides, currently stands at US$19.28/kW-month, that is, roughly double what it should be.

In practice, this is an indirect way of replacing the debt payment, to which consumers were already accustomed, with a new expense that both governments can use quite arbitrarily, as we have seen over the past two years. It is a way of reaching into the energy consumer's pocket to subsidize public policies, largely with an electioneering bias, that should be subject to the scrutiny of the federal budget and the fiscal framework. The analogy with the Severance Indemnity Fund (FGTS) is inevitable: a compulsory loan disguised as social protection, which creates slack for the government by relying on returns systematically lower than those of any minimally rational investment.

The second fact that strikes me as absurd is the recent claim by the Paraguayan government that the Itaipu tariff should not fall, as the Treaty requires, because the plant supposedly owes the country

a “historical debt”. Besides being vague, this narrative comes with no justification compatible with the amounts it refers to, and it serves precisely to sustain these wildcard expenses that suit both governments. The facts are clear: as cited by the distinguished Jerson Kelman in his recent article for the special edition of Canal Energia, “Setor Elétrico Rumo a 2050” (The Power Sector toward 2050), required reading for anyone who really wants to understand the subject, Paraguay has always had a positive result from the Itaipu tariff, and Brazil was an essential part of that because it alone guaranteed the loan to build the plant.

> As Claudio Sales, president of Instituto Acende Brasil, has pointed out, since the beginning of Itaipu Paraguay has received all the energy it could consume, always below the 50% to which it would be entitled, and it still obtained a positive financial result of around US$6 billion. Brazil, in turn, besides consuming its entire share, paid for decades for the energy Paraguay did not use, accumulating a negative result estimated at about US$90 billion.
>
> — Jerson Kelman, “Setor Elétrico Rumo a 2050”, Canal Energia, special edition, 2025.

Therefore, when these socio-environmental expenses are inflated, the distribution of these amounts falls disproportionately on the Paraguayan side compared with the cost borne by the Brazilian consumer. Nevertheless, both governments end up with more money for their “socio-environmental actions”, incentives that help explain the facts. Moreover, the operating agreement that resulted from the frustrating negotiations of 2024, by giving priority to the allocation of surplus energy to Paraguay after debt service ended in 2023, represented a new round of concessions and deepened the existing asymmetries to the detriment of the Brazilian consumer.

The problem, therefore, is neither technical nor economic. It is legal and ethical, as several voices in the sector have argued. By departing from the rules of the original Treaty, the governments break an agreement made with consumers more than 50 years ago, impose an enormous burden on tariffs and resort to constructed narratives to justify decisions that benefit precisely those who make them.

These two facts, absurd as they are, demonstrate the enormous cost caused by the limited regulatory and institutional maturity of countries that are still developing. This cost goes beyond the direct economic one, as it generates legal uncertainty, hidden cross-subsidies, risk premiums and a crisis of confidence among the Brazilian people themselves about the future of new treaties, including those originally well conceived, such as Itaipu.

Electricity Reform as Social Justice

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ABSTRACT

The consumer is the reason the electricity sector exists. Yet Brazil built a regulatory apparatus that treated the consumer as a passive agent, represented by third parties. The sector's institutions therefore developed almost entirely from the perspective of generation, and market power came to be exercised in the regulatory layer above the market. Over time, this protection became a regulatory prison. The exponential growth of distributed generation shows consumers escaping through its loopholes. I argue that this arrangement has reached its limit. There is no room left for individual subsidies, as the size of the Energy Development Account shows. It is also unfair that a regulation that does not evolve keeps consumers, renewable generators, and batteries from providing flexibility and ancillary services with technologies already available. Brazil is a stroke of the pen away from them. What is missing are regulatory foundations like those of Texas and California, where specific programs let consumers, aggregators, batteries, and hybrid arrangements participate in a technology-agnostic way. The optimal mix then emerges from each region's resources and opportunities. Inertia and the lack of leadership are the true ills to fight. Electricity reform is no longer only a modernization agenda. It has become a matter of responsibility and social justice.

The consumer is the reason the entire electricity sector exists. We produce energy only because someone needs it, consumes it, and pays for it. Yet the sector's own historical trajectory led to the construction of a regulatory apparatus that treated the consumer as an essentially passive agent, whose interests had to be represented by third parties.

This view made sense for a long time and will always have some validity. However, as a consequence of this way of approaching the electricity sector, institutional development took place almost exclusively from the perspective of generation.

In any market, including the most regulated ones, agents respond to incentives. Thus, all the major petitions, the debates over exceptions, and the disputes came to concentrate predominantly on the generation side. The long absence of leaders capable of consistently defending the sector's technical principles contributed to the gradual weakening of those principles, culminating in an environment in which practically all organized demands come from a single side.

The "protection" that followed from the consumer's passivity was internalized, and it proved extremely convenient for the workings of a sector model in which market power is exercised not through offers in the market itself but in the regulatory layer above it.

Over time, protection became a regulatory prison. A prison from which consumers try to escape through the loopholes opened by the very regulatory changes of recent decades. The exponential growth of distributed generation, a topic I discussed in *Revolution in Electricity Retail Challenges Regulation* (*Revolução no varejo elétrico desafia regulação*), is perhaps the most emblematic example of this movement.

The problem is that this arrangement has reached its limit. Not only because there is no more room for individual subsidies (I have in mind here the size of the Energy Development Account, or CDE, and the additional amount we will pay through the capacity reserve auction, or LRCAP, as a result of what we subsidized through the CDE), but because it is simply not fair that a regulation that does not evolve should keep preventing the use of technologies already available, technologies that would allow consumers, renewable generators (centralized or distributed), and batteries to create new business models and take an active part in the operation and expansion of the system by providing flexibility services and ancillary services.

Increasingly, the consumer plays an indisputable role in these new business models, especially with the arrival of large data-processing and

artificial intelligence training centers. The consumers and the system of the 1990s are very different from those of 2026.

For this reason, there is no other way forward than a reform of the sector. A reform that incorporates the values highlighted by Angela Gomes in her recent article *How to Make the Consumer the Protagonist of the Electricity Sector?*: balance, representation, and the centrality of the consumer. Everything else flows from this centrality.

For it is not good for the consumer that one source should prosper artificially, nor that the sources entering the market should be unable to make themselves viable through their own products and services. But this is no longer just a technical question. It is a question of justice for those who foot the bill at the end of the day.

There is no longer any justification for maintaining such a large regulatory imbalance between consumers and generators, nor such a deep mismatch between market design and the technological and operational reality of the system.

It is no longer acceptable, nor constructive, for us to keep repeating that renewable generators are merely intermittent sources that demand ever more subsidies, that thermal plants are merely polluting sources, that batteries create no value because they produce no net energy, or that consumers are all inflexible and do not respond to price. These statements reflect a view of the past, not of the present, and even less of the future.

Today's regulation either unlocks or buries the prosperity of the coming years. Inertia and the lack of leadership are, therefore, the true ills to be fought for the sake of what we want to build over the next decade.

The technologies already exist. Brazil is a stroke of the pen away from them. They can be imported, adapted, and even built here, if we invest in science and education. What is missing, in truth, are the regulatory foundations that would allow agents to internalize this new technological reality and to contribute, through competition and market incentives, to a system that is more efficient, cleaner, more resilient, and fairer.

All of this technological and regulatory apparatus already exists and is in full operation in the world's main electricity markets, where the effects of the massive integration of renewables have already been widely felt.

The Electric Reliability Council of Texas (ERCOT) and the California Independent System Operator (CAISO), the operators of the power systems of Texas and California, for example, have specific programs that allow consumers, aggregators, batteries, and hybrid arrangements to participate in the market in a technology-agnostic way.

Only in this way will we discover our own solutions, the arrangements that make sense for each region of the country. The optimal mix does not exist as a static figure. It emerges from the available resources, from technologies and innovations (ever more abundant), and from the specific opportunities of each region.

To deny these regulatory instruments is to prevent existing capabilities from flourishing. In an era of unprecedented technological transformation, keeping the sector trapped in a regulation of the past deprives a society that has talent, natural resources, and the will to prosper of one of the most valuable inputs for economic and social development: abundant, efficient, and clean energy.

Beyond that, market-design reform is perhaps the main latent issue of the Brazilian electricity sector. From it derive, directly or indirectly, a good part of the impasses we discuss every day: subsidies, expansion, reliability, rising costs, risk allocation, and distorted economic signals.

That is why the reform of the electricity sector is no longer just a modernization agenda. It has become a matter of responsibility and social justice.

The Institutional Deterioration of the Brazilian Electricity Sector

The weakening of institutions threatens the efficiency and modernization of the Brazilian electricity sector

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ABSTRACT

I argue that the recent war over the capacity auction exposed a gradual deterioration of the institutional capacity of the Brazilian electricity sector. In mature markets, auctions and other market mechanisms exist to discover the winning technologies through competition for the lowest price. Auctions should therefore focus on the product, whatever the source that produces it. Where a two-settlement system operates, agents trade 24 hourly contracts for the next day, and a real-time market settles deviations every few minutes. Under these prices, renewable plants rarely enter the market without batteries. Brazil has restricted competition by technology in practically every new-energy auction since 2005 and has discussed market-design reform for more than a decade. Neither stems from a lack of technical knowledge. Both reflect institutions that are losing the capacity to plan, regulate, and reform. Neglected budgets at the planning agency and the regulator, and tensions between the ministry and the regulator, are the clearest symptoms. Expansion is increasingly driven by lobbies, narratives, and subsidies. Without a broad market reform, the sector will keep postponing the measures that attack the causes: prices closer to operation, integrated day-ahead and real-time markets, demand response, ancillary-service markets, and explicit value for flexibility and reliability. At bottom, the problem is one of leadership.

Perhaps the most worrying point in the whole recent debate in the electricity sector about the capacity auction is that we have forgotten something basic: in mature markets, the central debate is rarely about which technology should "win." The role of the market and of its mechanisms, such as auctions, is to discover the winning technologies, not to determine them. Markets should be technology-agnostic: the optimal resource mix should be an outcome, a selection by fitness to deliver the specified attributes through competition for the lowest price.

That is why it is so important to design auctions with a focus on the product, and not on which source will produce it. It is no accident that there are arrangements in which batteries and thermal plants are used in a complementary and joint way by the developers themselves, in different contexts, to capture higher prices in specific ancillary-service products.

This is particularly evident in mature markets that operate with a two-settlement system. In them, every day, agents trade, through a centralized auction, a set of 24 hourly financial contracts, one for each hour of the following day. The aim is to balance supply and demand at the lowest possible cost, while respecting network constraints, the operating limits of generators, and the security requirements of the system.

On the day of operation, a real-time market settles the differences between what was contracted and what was actually generated or consumed, usually in intervals of a few minutes, reflecting the actual conditions of the system.

That is why, in mature electricity markets, where real-time prices reflect the operating conditions of the system more faithfully, renewable plants rarely enter the market without batteries. Whoever injects energy beyond what was contracted at times of system-wide surplus receives very low prices. Whoever fails to deliver the scheduled energy in periods of scarcity must buy it back at prices that can be extremely high.

The market itself turns, in just the right measure, forecast errors, lack of flexibility, and the variability of renewables into economic costs for their owners, creating clear incentives for investment in storage and flexibility.

However, this is perhaps a deeper problem of our sector. We still find it enormously difficult to trust the ability of market mechanisms to reveal efficient combinations of technologies and new operating arrangements. Instead, we insist on interfering with the discovery process that the market promotes, imposing our own convictions about which technologies should prevail.

To a greater or lesser degree, restricting competition by technology has been the reality of practically every new-energy auction we have held since 2005. Moreover, for more than a decade we have been discussing a reform of the market design to bring prices closer to operation and thereby reduce the need for subsidies. The problem is that neither of these phenomena can be attributed to a lack of technical knowledge or of international references. Both reflect a gradual deterioration of the sector's institutional capacity to plan, regulate, and carry out long-term structural reforms.

In the midst of a veritable war over the capacity auction held in March 2026, what is at stake, however, is not deciding which technology is more or less appropriate for the moment the sector is in. What we are really discussing, and the precedents we are setting, even without being fully aware of it, is how we will carry out the expansion of a complex power system, a task that has historically always depended on planning and on market mechanisms or, ideally, on efficient coordination between the two, something we have never fully achieved.

Decades of research in market design, planning, and operation, a vast theoretical and practical literature, billions invested in studies, institutions built, and highly qualified staff. Even so, we have reached a point at which expansion is starting to be determined more by lobbies, convenience, and narratives than by economic, operational, and planning fundamentals.

The result is what we are now seeing: an institutional and sectoral deterioration that is ever more evident and ever more costly for the consumer. We have completely left a stable regulatory equilibrium, one in which a disturbance is corrected with technical rigor, established procedures, and observance of basic principles of engineering and economics.

The neglect of the budgets of the planning and regulatory bodies, the Brazilian Energy Planning Agency (EPE) and the Brazilian Electricity Regulatory Agency (ANEEL), in recent years is perhaps the most evident symbol of this process. And this is happening precisely at the time when the system is going through its greatest transformation and therefore demands more analytical capacity to support studies and to make regulatory change possible. At the same time, we have accumulated institutional tensions between the ministry and the regulator, disputes that erode credibility, coherence, predictability, and the capacity to execute. It was in this environment that a new modus operandi took hold in the sector.

The risk is evident: when planning weakens, the market does not mature, and market signals cease to reflect the actual operation of the system, expansion stops being the pursuit of system-wide efficiency. It comes to be guided by the pursuit of subsidies, sectoral pressures, and institutional disputes, often resolved outside the market design itself, including in the courts.

More broadly, the whole current debate in the sector, from the level of risk aversion in the official models that form short-term prices, through the recurring crises of liquidity and market security, to the capacity auctions, is not focused on modernizing or improving the sector. At bottom, it seeks only to shift, through subsidies, disputes, and improvisation, the costs of a market reform that was planned but never actually implemented.

Until we organize ourselves as a sector to promote a broad market reform and put the system back on a path of efficiency and predictability, we will keep postponing precisely the transformations that could tackle the structural causes of today's problems: a closer alignment between prices and operation, integration between day-ahead and real-time markets, demand response, ancillary-service markets, and mechanisms capable of explicitly valuing flexibility and reliability. Instead, we will keep reacting to crises, redistributing costs, and treating symptoms, while the structural causes remain untouched.

Unfortunately, the regulatory confusion the sector lives with today is, to a large extent, the reflection of a gradual abandonment of the

principles that sustained technical discussion, established procedures, and care for institutions and their roles. And since principles manifest themselves only through people, it becomes clear that, at bottom, the problem is one of leadership.

Chapter 10

An Agenda for 2027

2026

In this chapter

An Agenda for Brazil's Electricity Sector from 2027 Onward 162

Introduction

The government that begins its term in 2027 will inherit an electricity sector different from the one the 2004 reform envisioned. Brazil built a highly renewable mix, attracted private investment, and expanded generation, but the markets that coordinate operation and guide investment did not modernize with it. The result is a paradox. The country has abundant renewable energy but finds it increasingly difficult to use, pays a high cost to ensure supply, and has tariffs that undermine its competitiveness. I wrote the article of this chapter in October 2026 as an agenda for that government. It gathers in one place proposals that the earlier chapters develop one by one, and it closes the history this book tells.

The problem lies in institutions that did not adapt to a new technological reality, and it cannot be blamed on the energy transition or on any particular source. The system was designed when hydropower provided both energy and operational flexibility. Wind and solar changed that relationship. During the day, solar displaces the output of other plants, and at sunset its withdrawal requires a rapid increase in controllable generation. Renewable forecast errors must also be balanced continuously. Flexibility, once abundant, has become valuable, but no price adequately reveals its value. Each need therefore gives rise to a new charge, subsidy, or contract, and the costs accumulate like compound interest. The Energy Development Account, which collects sector subsidies through consumers' tariffs, has grown on average 16.5% a year since 2004. At sunset, when tens of gigawatts of distributed solar stop contributing to supply, the government procures resources connected to the high-voltage grid through long-term capacity auctions. That choice is based on a logical leap, the assumption that long-term procurement is the best way to correct the failures of a short-term market that does not price the services the operation requires.

The agenda works on three fronts. The first brings prices closer to the physical operation of the system. Day-ahead and real-time markets would operate under two-settlement, so that whatever an agent delivers or consumes beyond its day-ahead position is settled at the real-time

price. Those prices would be linked to an optimized dispatch every ten minutes. Ancillary services, above all the reserves that compensate for renewable variability and uncertainty, would be priced through competitive, technology-neutral mechanisms open to hydro plants, thermal plants, batteries, and consumers. Their costs would follow cost causation, so that whoever causes a cost bears it. In December 2025 the Texas system operator introduced the co-optimization of energy and ancillary services, with estimated benefits above US$1 billion.

The second front redesigns expansion. Auctions would stop procuring predetermined technologies and quantities and would evaluate the integrated contribution of each project, including the entry of large loads such as data centers. The Brazilian Energy Planning Agency already has extensive experience with planning models that integrate generation, storage, transmission, and reliability. These models can select the projects that minimize total system cost.

The third front modernizes retail. Households need prices combined with technology, as happened with appliances during the 2001 rationing. Commercial and industrial consumers need distribution companies whose remuneration no longer centers on returns on capital expenditure. They also need local flexibility markets integrated with the wholesale market through aggregators and retail suppliers.

None of this replaces planning with a deregulated market. The agenda requires planning integrated with the market, economic instruments consistent with operation, and gradual implementation with testing, a public timetable, and legal certainty. Opening the retail market should expand choice without hiding costs in charges. I summarized the agenda for the next government in one sentence, “we need fewer exceptions and better rules”.

Core ideas

1 The government of 2027 inherits a paradox of abundant renewable energy, growing difficulty in using it, high costs to ensure supply, and tariffs that undermine competitiveness.

2 The problem lies in institutions that failed to adapt to the new technological reality. It cannot be blamed on the energy transition or on any particular source.

3 Flexibility, once abundant, has become valuable, and without prices that reveal its value every need produces a new charge, subsidy, or contract.

4 The Energy Development Account has grown on average 16.5% a year since 2004.

5 The first front brings prices close to physical operation, with two-settlement, prices every ten minutes, and competitive, technology-neutral ancillary services whose costs follow cost causation.

6 The second front redesigns expansion auctions to value each project's integrated contribution, including large loads such as data centers, with the planning models the sector already uses.

7 The third front modernizes retail, combining prices with technology, reforming the remuneration of distribution companies, and creating local flexibility markets.

8 The agenda keeps planning and integrates it with markets, through gradual implementation, a public timetable, and legal certainty.

Conclusions

The agenda for 2027 turns the argument of this book into decisions. It joins three fronts: prices close to operation, expansion auctions that value what each project adds to the system, and a retail market able to put the flexibility of households, firms, and distribution networks to use. The next government will choose between addressing the structural causes and continuing to manage their consequences.

The articles

An Agenda for Brazil's Electricity Sector from 2027 Onward, published in CNN Brasil on 22 October 2026, is the last article of the book. I wrote it as a program for the government that begins in 2027, and it sets out the agenda as three fronts and a closing principle, "fewer exceptions and better rules". The afterword that follows looks at the conditions under which this agenda can succeed.

An Agenda for Brazil's Electricity Sector from 2027 Onward

The next administration will need fewer exceptions and better rules to reduce the cost of energy and turn the electricity sector into an engine of economic development

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ABSTRACT

The administration that begins in 2027 will find an electricity sector different from the one the 2004 reform envisioned. Brazil built a highly renewable mix, but its markets did not modernize with it. The result is a paradox of abundant renewable energy, growing difficulty in using it, high costs to ensure supply, and tariffs that undermine competitiveness. I argue that the problem lies in institutions that failed to adapt. Flexibility, once abundant, has become valuable, yet no price reveals its value. Each need therefore produces a new charge, subsidy, or contract, and the Energy Development Account has grown 16.5% a year on average since 2004. The next government can halt this process on three fronts. The first is to bring prices close to physical operation, with day-ahead and real-time markets under two-settlement, ten-minute prices, and technology-neutral ancillary services whose costs follow cost causation. In Texas, co-optimizing energy and ancillary services since December 2025 has estimated benefits above US$1 billion. The second is to redesign expansion auctions so they value each project's integrated contribution, including large loads such as data centers. The third is to modernize retail, reform distribution remuneration, and create local flexibility markets. None of this replaces planning with deregulation. We need fewer exceptions and better rules.

The next administration will inherit an electricity sector different from the one envisioned by the 2004 reform. Brazil has built a highly renewable electricity mix, attracted private investment, and expanded generation. Yet this expansion has not been accompanied by the modernization of the markets that coordinate system operation and guide investment.

The result is a paradox: we have abundant renewable energy, but growing difficulties in making use of it, high costs to ensure resource adequacy, and tariffs that undermine competitiveness. The problem lies neither in the energy transition nor in any particular source, but in the failure to adapt institutions to the new technological reality. How this challenge is prioritized will depend on the objectives of the next administration.

Brazil's electricity system was designed when hydropower provided both energy and operational flexibility. The expansion of wind and solar generation has changed this relationship. During the day, photovoltaic generation displaces output from other power plants; at sunset, its withdrawal requires a rapid increase in controllable generation. Renewable forecast errors must also be continuously balanced.

Flexibility, once abundant, has become valuable, yet the market still lacks prices that adequately reveal its economic value, despite international experience.

The consequences reinforce one another. Without prices for operational services, batteries, demand response, and other sources of flexibility lack incentives. Technology-specific subsidies encourage new projects even when their additional contribution is small. When renewable generation exceeds demand or transmission capacity, the operator orders compulsory cuts, the so-called curtailment.

At the same time, at sunset, when tens of gigawatts of distributed solar generation stop contributing to meeting demand, the government procures, through capacity reserve auctions, resources connected to the high-voltage grid for long periods, passing the costs on to consumers.

Neither resource adequacy nor the importance of auctions is in question. The issue is the logical leap that long-term procurement is

the best way to address the failures of a short-term market that does not price the services the operation requires. Without correcting the source of the problem, each need gives rise to a new charge, subsidy, or procurement. Solutions presented as "pragmatic" conceal structural problems, whose costs accumulate like compound interest.

The Energy Development Account (CDE), which has grown by an average of 16.5% per year since 2004, illustrates the advance of charges. The result is a sector that is more complex, more costly, and more dependent on administrative decisions.

The next administration can halt this process on three fronts.

The first is to bring prices closer to the physical operation of the system, a basic principle widely violated in Brazil. Day-ahead and real-time markets, operating under a two-settlement system with prices linked to optimized dispatch every ten minutes, would reveal the value of energy across different hours and locations. Ancillary services must also be priced, particularly the reserves that compensate for renewable variability and uncertainty. Their remuneration should be competitive and technology-neutral, allowing hydropower plants, thermal plants, batteries, and consumers to participate.

The costs of these reserves should be allocated according to cost causation, avoiding undue transfers. The Electric Reliability Council of Texas (ERCOT), the Texas system operator, reduced its real-time market intervals from 15 to five minutes in 2010 and introduced the co-optimization of energy and ancillary services in December 2025, with estimated benefits exceeding US$1 billion.

The second is to redesign how the system expands. Auctions should move away from procuring predetermined technologies and quantities toward evaluating the integrated contribution of each project, including the entry of large loads such as data centers. The value of a power plant depends on when and where it produces, the flexibility it provides, transmission, and its complementarity with the existing fleet, not merely on the price of energy or of firm capacity.

Planning models already used in the sector, in which the Brazilian Energy Planning Agency (EPE) has extensive experience, make it possible to integrate generation, storage, transmission, and reliability

to select projects through an auction that minimizes total system costs. Auctions can incorporate bids from large consumers for grid access, making their entry conditional on contributions that cover the additional costs of integration.

This would position Brazil as a hub for generation and large loads, with economic accountability, preserving centralized planning and using competition to select investments.

The third is to modernize retail, recognizing differences among consumers and offering incentives for them to respond to system conditions. In the residential segment, changing tariffs alone has a limited effect. Prices must be combined with technology, as happened with household appliances during the 2001 rationing, now to promote flexibility.

The challenge involves not only consumption but also distributed solar injection. International experience shows how to encourage batteries and devices that automatically adjust their operation to the needs of the system without compromising comfort. This requires a ministerial agenda coordinated with the equipment industry.

In the commercial and industrial segments, economic returns encourage demand management and the provision of flexibility more directly. Unlocking this potential requires reforming the remuneration of distribution companies, currently centered on returns on capital expenditures (CAPEX), and developing local flexibility markets, new remuneration and payment mechanisms, and new business models, as in the United States and Europe. These markets must be integrated with the wholesale market, with the participation of aggregators and retail suppliers.

These fronts do not mean replacing planning with a deregulated market. They require planning integrated with the market, economic instruments consistent with operation, and gradual implementation, with testing, a public timetable, and legal certainty. Retail market opening should expand choice without hiding costs in charges.

Brazil can turn its electricity mix into a lasting competitive advantage. The challenge is not to pick winning technologies, but to create rules capable of attracting the resources needed. A successful energy policy

delivers reliable, clean, and affordable electricity. We need fewer exceptions and better rules.

Complex problems rarely admit simple solutions, but the sector has already demonstrated its ability to address them. Without comprehensive reform, a strategic advantage will continue to generate costs and obstacles to development. The next administration will have to choose between addressing the structural causes and continuing to manage their consequences.

Afterword — Looking ahead

What happens next in the Brazilian electricity market will depend less on technology than on decisions. Those decisions belong to the country's leadership, to the Ministry of Mines and Energy, and to the institutions of the sector. I want to close this book with a look at the future. I am cautiously optimistic, because Brazil has what it needs to correct its course. I am also critical, because the last decade shows how easily that chance can be lost.

What the country has

Brazil has the renewable resource, the technology, and the capital willing to finance it. The sector also has decades of research in market design, planning, and operation, institutions built over time, and highly qualified technical staff. As I wrote in *The Confusion over Prices and Risk Aversion in the Power Sector*, what we lack is coherence and leadership, and the rest the sector has in abundance.

The National Electric System Operator has recently taken responsibility for the computational models that plan the operation and form prices. This decision creates the institutional and technical conditions to bring the network, real time, and reserves gradually into price formation, provided that the other institutions of the sector follow and encourage the process.

Brazilian consumers have shown, more than once, that they respond to prices. In the 2001 rationing, they chose more efficient appliances themselves to avoid the surcharge on those who missed their reduction target, in what was perhaps the largest demand-response program in history. From 2022, households used distributed generation to build

a market for credits inside the regulated segment. In the same year, the regulator created a voluntary demand-response program that gave large consumers a market for their flexibility, and in October 2024 it had already exceeded 9 GWh.

The reform agenda has also been available since 2017, when Public Consultation No. 33 outlined sequential real-time markets and a short-term market closer to the operation. The new government of 2027 opens a window to act on it. We can also learn from the trials and errors of markets that are about fifteen years ahead of us in integrating non-controllable resources. In December 2025, the Electric Reliability Council of Texas, the system operator of Texas, began to co-optimize energy and ancillary services, with benefits estimated at more than US$1 billion.

What could go wrong

The capacity contracts signed in March 2026 run for 10 to 15 years, and their cost reaches consumers through a charge. Each new auction of this kind deepens the lock-in to designs chosen before prices were corrected, and agents that come to feel entitled to a guaranteed revenue rarely give it up. Subsidies keep accumulating, and the Energy Development Account has expanded at an average rate of 16.5% a year since 2004. Tariffs have become so high for final consumers that they must be paid in installments at compound interest. The battery auction under consultation in 2026 risks repeating, with storage, the pattern of the capacity auction. The Brazilian Energy Planning Agency and the regulator have seen their budgets neglected, and the friction between the ministry and the regulatory agency erodes credibility and the capacity to execute. At bottom, as I wrote more than once in 2026, each of these risks is a problem of leadership.

The conditions

The optimistic path depends on doing things in the right order. Markets that went through this transition before us show that many problems

are avoided when price formation in the short-term market is organized first. My articles point to five conditions.

1. Prices come first. Day-ahead and real-time markets operate under two-settlement, which charges or pays every deviation from the day-ahead schedule at the real-time price. Prices are set every ten minutes, and ancillary services are priced through competitive, technology-neutral mechanisms.
2. Subsidies are reduced gradually yet swiftly, and no new subsidy is created to correct the side effects of an older one.
3. Expansion auctions are open to every technology and value each project's integrated contribution to the system, using planning models already in use in the sector.
4. Consumers and distribution networks take part in the market through aggregators, retail suppliers, and local flexibility markets, together with a reform of how distribution companies are paid.
5. The institutions recover their capacity, with an operator that chooses its own models and answers for its results, and with planning and regulatory bodies that have the budgets their tasks require.

If these conditions are met, with prices first, capacity and storage contracts can play the complementary role they play in mature markets, and the costs now paid through charges can return to prices that show agents where to invest. If they are not met, the sector will soon be discussing the same problems again.

From Latin America to the United States

On 5 and 6 November 2026, Frank Wolak and I organized a two-day workshop at Stanford University. Its title was *From Latin America to the United States: Challenges, Models, and Policies for Electricity Markets in Transition.* It was supported by the Center for Latin American Studies, with the sponsorship of the Tinker Foundation, and it brought together system operators and academics from both hemispheres. The operators came from the California Independent System Operator, the

Electric Reliability Council of Texas, the Southwest Power Pool, the Midcontinent Independent System Operator, PJM Interconnection, the New York Independent System Operator, and ISO New England, and from Brazil's National Electric System Operator and Chile's National Electric Coordinator.

The rapid integration of intermittent renewables worldwide has raised concerns about long-term supply adequacy in markets increasingly dominated by resources with zero marginal cost. Hydro-dominated Latin American countries have been addressing this challenge for more than two decades with long-term instruments and market designs of their own. The United States and Europe have largely addressed the problems of solar and wind through short-term price signals more closely aligned with the operation and through long-term capacity mechanisms. The workshop explored how short-term signals and long-term instruments interact in renewable-dominated markets with low marginal costs.

The lessons of systems that have already gone through the scarcity of flexibility and the massive entry of renewables matter greatly to Brazil and to the rest of Latin America, whose systems grew from a very different availability of resources. Latin America also has lessons to offer. It brings formats of long-term contracting, mechanisms, and auctions that are critical where load grows fast, and Brazil's experience with forward markets and auctions is part of that contribution. The United States offers short-term products designed to signal scarcity.

In 2004 Brazil designed a market for a hydro system with fast-growing load. The task now is to redesign it, with the same care, for a system in which flexibility has become scarce.