NAVIGATING THE ENERGY TRANSITION IN LATIN AMERICA AND THE CARIBBEAN

Volatility and price signaling in short-term electricity markets

Lenin H. Balza • Carlos Mata • David Matías • Ricardo Ríos

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SUMMARY

The sharp increase in fossil fuel prices, exacerbated by extreme climate events such as prolonged droughts, has led to significant short-term price volatility in electricity markets across Latin America and the Caribbean. Simultaneously, the rapid integration of variable renewable energies, such as solar and wind, presents new operational challenges for electricity markets. This situation has intensified the debate on the optimal design of electricity markets, particularly regarding economic efficiency and effective price signaling during the energy transition. In this context, questions arise about which regulatory adjustments could improve short-term price signals and ensure efficient and competitive dispatch. **This report examines the key components of short-term electricity markets in Latin America and the Caribbean, identifies international best practices, and pinpoints the primary sources of spot price volatility.** Additionally, it provides regulatory recommendations to enhance the integration of variable renewable energies into the energy mix, strengthen resilience, and optimize the operational efficiency of electricity markets.

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ABSTRACT - KEY FINDINGS AND POLICY CONSIDERATIONS

ABSTRACT - KEY FINDINGS AND POLICY CONSIDERATIONS*

The design of electricity markets is the centerpiece of the debate on how to develop sustainable, affordable, and secure energy markets in Latin America and the Caribbean. Since the transformations that began in the 1990s, regulatory frameworks in the region's electricity sector have continuously been adapted to respond to needs regarding the continuity and quality of the electricity supply, the promotion of new investments, technological innovation, environmental sustainability, affordability, and the promotion of competition, among others. The relevance of the market design lies in the fact that the proper formation of electricity prices allows the correct transmission of signals to market participants, from domestic, commercial, and industrial consumers to generation, transmission, distribution, and commercialization companies. While Latin America and the Caribbean has made progress in developing wholesale electricity markets for long-term transactions, short-term or spot markets are still relatively nascent in several parts of the region.

Recent volatility in short-term electricity prices, caused by rising fossil fuel prices, adverse natural events, and the integration of variable renewable energies (VREs), has highlighted the need for structural reforms in wholesale electricity markets in Latin America and the Caribbean, as well as in other regions across the globe. Although the impact and responses of countries to these challenges have been diverse, reflecting their different energy matrices and national priorities, it is evident that there are significant opportunities to improve efficiency in the operation of the markets. The first step towards this reform is to identify the factors that influence the formation of wholesale electricity prices, in order to differentiate the elements that distort prices from those that are inherent to the composition of the underlying energy matrix.

The transformation of electricity markets is characterized by the integration of variable renewable energies, such as solar and wind, which poses unprecedented challenges in terms of market design. The introduction of new technologies requires a systematic review of market design, and the introduction of regulations and strategies aimed at facilitating the transition to variable renewable energy sources in electricity grids. The short-term wholesale markets segment faces even more significant challenges, as it is the most heavily impacted by VREs. They introduce significant uncertainty and variability in short-term generation, inducing spot prices close to zero, which could eventually affect investment in the electricity sector.

This report is an initial effort to understand the current state of liberalized electricity market designs in Latin America and the Caribbean, identifying their challenges and opportunities. The purpose of this document is to present the main regulations and market rules that influence price formation in short-term wholesale markets in the region, as well as the best practices observed in the main markets of the United States and Europe to better signal prices that accurately represent supply and demand conditions while facilitating an efficient and transparent electricity dispatch that promotes the integration of cleaner technologies in the electricity matrix. This study specifically seeks to: a) identify the main factors that influence short-term wholesale price formation processes in electricity markets; b) extract lessons learned from the debates on European electricity market reforms; c) analyze the main characteristics of short-term markets in liberalized markets in Latin America and the Caribbean; and d) discuss the main challenges and best regulatory practices that Latin American and Caribbean countries could implement, based on the experiences of the main electricity markets in the United States and Europe.

* This document was originally composed in Spanish. The present English translation is provided to ensure broader accessibility for an international readership.

Short-term market highlights in Latin America and the Caribbean

The design of short-term liberalized markets in Latin America and the Caribbean has been developed based on the particularities and unique characteristics of each country, including the availability of resources and institutional capabilities. These markets are characterized by structures where prices are more regulated or subject to greater intervention by operators and regulators than in the electricity markets of the United States or Europe. In some cases, this intervention results in short-term prices that do not reflect agents' opportunity cost, which has implications for their behavior, the investment decisions, and the financial viability of the operations of electric utilities. In order to identify possible regulatory adjustments to increase efficiency in the operation of these markets, it is key to identify the main characteristics of short-term wholesale markets in the region, as described below. This analysis will allow us to pinpoint areas for improvement and develop strategies to optimize market efficiency in the short term.

Highlight 1. The allocation of electricity dispatch based on merit order and marginal cost remuneration has been the most widely used model in short-term electricity markets

This approach, adopted both in Latin America and the Caribbean and in the main electricity markets of the United States and Europe, primarily favors renewable plants because of their lower marginal cost, which tend to have lower greenhouse gas (GHG) emissions, leaving the more costly and generally more polluting options in the background.

Highlight 2. The design of short-term electricity markets is still at an early stage in most Latin American and Caribbean countries

The high integration of water sources with storage capacity and high levels of flexibility has minimized the need to develop short-term markets. Historically, markets based on thermal and hydro technologies have been properly managed with weekly or, in some cases, daily schedules to plan electricity generation. Yet, these designs are not adequately prepared to deal with increasing levels of variable renewables, the required flexibility, the energy spillovers, and, in some cases, prolonged periods of near-zero marginal costs. In contrast to Latin America and the Caribbean, the electricity markets in the United States and Europe have advanced more rapidly in developing regulatory frameworks that allow for the efficient integration of these technologies into the electricity sector. This progress has resulted in more accurate price signaling in terms of spatial location and time.

Highlight 3. Short-term electricity markets in Latin America and the Caribbean are cost-based, where generators' bids are audited to ensure that the marginal cost accurately reflects the actual cost

This model responds to concerns about the risk of price manipulation, concentration in some electricity markets and lack of institutional capacity in the region. Colombia and the Regional Electricity Market (REM) in Central America are bid-based markets in Latin America and the Caribbean. On the other hand, Mexico has implemented a bid system limited to a margin defined by audited costs. In contrast, the markets in the United States and Europe operate on a bid-based model, which significantly diverges in terms of structure and operation compared to Latin American and Caribbean markets.

Highlight 4. Spot markets in Latin America and the Caribbean have generally used zonal or single prices, although some countries have nodal prices

Except for Chile, Peru, Mexico, and the Regional Electricity Market (REM), which have nodal markets, zonal or single prices prevail in most of the countries in the region. Markets with zonal or single-price pricing face the risk of high economic costs during the redispatch process, especially if transmission system constraints are not effectively considered. They also fail to provide adequate price signals for the development of transmission infrastructure and other energy solutions, especially in single-price markets. Without accurate congestion signals, investments are less likely to be made where they are most needed.

Highlight 5. Most electricity markets in Latin America and the Caribbean have single settlement systems, which limits their efficiency

The integration of new technologies demands the development of new market designs for better price signaling. Many markets currently use a day-ahead market (DAM) which, in some cases, is not financially binding. Such markets rely on prices in the real-time markets (RTM). International experience suggests that two markets would help to better signal short-term prices, allowing prices to efficiently reflect current supply and demand conditions, as is the case in the USA with a DAM and an RTM or in Europe with a DAM and an intraday market (IDM).

Highlight 6. Ensuring competition following the deregulation of electricity markets has been challenging

Despite the existence of cost-based markets in Latin America and the Caribbean, the risk of price manipulation and capacity withholding practices persists. This situation has led to the implementation of regulatory mechanisms, competition monitoring units, and the establishment of maximum prices in spot markets in the region. This problem, however, is not exclusive to Latin America and the Caribbean; in the United States and Europe, markets often exhibit imperfect competition and high concentration. During the last energy crisis in the European Union, one of the main challenges discussed to increase the affordability of electricity prices revolved around improving the regulatory framework and implementing measures to let more competitive markets develop.

Highlight 7. Most of the electricity in Latin America and the Caribbean is traded in long-term markets, while short-term markets are less relevant

The high integration of hydropower in the electricity matrix of several Latin American and Caribbean countries has resulted in low and volatile prices in spot markets due to the dependence on climatic factors that affect the availability of water resources. This volatility has driven the development of long-term markets with the aim of encouraging investments in power generation, providing financial certainty to investors. These markets have been crucial for the development of the electricity sector in the region, as they offer stability through contracts that mitigate the fluctuation of spot prices, benefiting both generators and distributors as well as end consumers by guaranteeing more stable tariffs.

Highlight 8. The composition of the electricity generation portfolio directly influences the marginal cost, which determines short-term electricity prices

In countries such as Mexico and Argentina, where natural gas plays an important role in the electricity matrix, natural gas prices significantly influence spot prices. On the contrary, in countries where hydroelectricity plays a major role, such as Brazil and Colombia, prices are usually determined by the opportunity cost of the stored water. In addition, in countries with a growing integration of solar and wind sources into the electricity matrix, there is a trend towards very low or close to zero prices during the periods of the day when these sources can meet a large portion of the demand. However, prices are higher when generation from these sources is insufficient or non-existent to meet high demand, requiring the entry of generators with higher marginal costs.

Highlight 9. Incorporating solar and wind into the electricity matrix introduces unique challenges, primarily due to the need to manage their intermittency and ensure they are balanced with other technologies

To manage this variability, it is necessary to increase the flexibility of the electricity system. In countries such as Chile and Uruguay, it has been observed that when renewable energy generation operates at maximum capacity, marginal prices tend to be very low or even zero. This leads to a reduction in average electricity prices, but also to a higher variability of these prices. There may also be a problem of excess generation, where the transmission capacity is insufficient, and unconsumed energy must be dumped. This situation affects the revenues of generators that operate mainly in the spot markets and may discourage investment in new generation capacity. It is crucial that markets incentivize investment in technologies that increase the flexibility of the electricity system, such as energy storage systems, demand-side management, and transmission infrastructure expansion. It is also necessary to create new competitive markets for essential products such as reserves, flexibility, and regulation. The current configuration of most electricity markets does not effectively promote this type of investment, which poses a challenge to efficiently integrating variable renewable energies into the energy matrix.

Highlight 10. The region is in a growing stage of electricity market integration. Regional collaboration, facilitated by the Central American Electrical Interconnection System (SIEPAC) and several bilateral connections between countries, offers significant benefits

Evidence suggests that energy trading at the regional level can play a crucial role in managing stress situations in electricity systems, encourage the adoption of renewable energies, and promote a more efficient use of generation technologies and transmission infrastructure between countries. For example, In Europe, regional integration has proven to be an effective strategy for dealing with recent energy crises, representing an especially useful solution when a country faces difficulties in its energy generation capacity.

Policy considerations

Short-term electricity markets in Latin America and the Caribbean share similarities with those of the United States and Europe, but also show significant differences. Although these markets have evolved differently in their operation, they have all implemented reforms aimed at improving efficiency in the management of electricity generation. A decentralized market model predominates in Europe, while in the United States electricity dispatch is centralized. In Latin America and the Caribbean, dispatch remains highly centralized, and power plant bids are subject to regulatory audits.

This report attempts to identify the regulatory elements that could be maintained, reformed, or updated in wholesale electricity markets in Latin America and the Caribbean, using the experiences of the United States and Europe as a reference. Although these changes must be evaluated according to the particularities of each country, the main purpose is to identify possible regulatory improvements for wholesale electricity markets in the short-term. Considerations on the adjustments needed to improve the efficiency and resilience of these markets will be discussed below.

Policy Consideration 1. It is essential to review and update the design of electricity markets in the short-term to improve efficiency in electricity dispatch, provide the right signals for investment, and decarbonize the electricity matrix

The diversity of electricity systems in Latin America and the Caribbean requires a detailed assessment of each market to determine which adjustments to the current regulatory framework could increase the efficiency of the electricity market in the short term. The implementation of a marginal remuneration system in these markets is considered to be the most effective option to maximize the efficient use of electricity system resources compared to alternatives such as the pay-as-bid method. Major regulatory changes include the transition to bid-based markets, the implementation of multiple-settlement markets, and increased geographic and temporal granularity of markets. These regulatory reforms are necessary to achieve the proposed objectives of decarbonizing electricity grids.

Policy Consideration 2. The transition to nodal markets could reduce the costs associated with redispatch, although one must recognize the inherent complexity of this approach

The implementation of nodal prices must consider the specific conditions of each market and its level of development. Nodal pricing makes it easier for changes in supply, demand, and network conditions to be reflected in prices, thus promoting a more efficient allocation of resources. Besides providing signals for generation, nodal markets also provide economic signals for the development and optimal location of transmission infrastructure, encouraging investments where they are most needed. While local prices may be more volatile, market participants can mitigate, to some extent, the impact of these variations through financial instruments such as Financial Transmission Rights.

Policy Consideration 3. The adoption of multi-settlement markets with finer time granularity plays a crucial role in effectively integrating variable renewable energy sources and flexible technologies into the electricity grid

The inherent variability of solar and wind generation makes regulation necessary in order to promote the proper integration of these resources into the electricity system. Latin American and Caribbean markets should evaluate the transition from a single- to a multiple-settlement model. That is, that the market design includes both a day-ahead market (DAM) that is financially binding and an intraday market (IDM) or a real-time market (RTM). International experience suggests that these markets facilitate the incorporation of a higher percentage of variable renewable technologies in generation portfolios. This is achieved through improved short- and long-term price signals, which allow for increased flexibility. Allowing bids to be submitted minutes, rather than hours, before electricity dispatch would make it easier for market participants to transact as close as possible to the actual time of electricity supply. This could optimize the use of renewable energies, reducing the costs associated with imbalances.

Policy Consideration 4. Promoting a favorable environment for the development of wholesale markets that foster competition would lead to more affordable prices. This must be combined with effective sanctioning mechanisms to combat anti-competitive practices

The persistent concern among regulators and operators regarding market concentration underscores the need to promote competition, as was originally intended with market deregulation. Any regulatory change must consider competition as a desirable goal. Policy measures to ensure effective competition include: (1) ensuring free and unrestricted access to the transmission network to facilitate the equitable participation of all wholesale market players; (2) the effective separation of transmission operations from the activities of generation, retail and distribution/marketing companies to avoid conflicts of interest and promote fair competition; (3) promoting independence between market operators and regulatory entities to ensure market efficiency and transparency; and (4) establishing market power mitigation mechanisms, effective surveillance systems against anticompetitive practices and the implementation of corresponding sanctions to preserve competition in the markets.

Policy Consideration 5. Diversifying the power generation portfolio can help mitigate periods of stress in electricity markets

The integration of alternative technologies to fossil fuels into the electricity matrix—such as hydroelectric, solar, and wind power—not only decreases dependence on natural gas, coal, and oil prices, but also contributes to a sustained reduction in average spot electricity prices. This is particularly relevant for countries that currently rely heavily on fossil fuels. The transition to renewable energies, such as solar and wind, has proven to be an effective strategy for reducing electricity costs in countries that traditionally relied on fossil fuels. Furthermore, in countries with large hydroelectric generation—which often find expansion difficult and suffer the negative effects of climate change—it is crucial to add alternative energy sources to reduce the impact of extreme weather events. This diversification policy not only promotes sustainability and energy security, but also fosters economic stability by protecting all consumers from extreme fluctuations in energy prices.

Policy Consideration 6. The incorporation of solar and wind sources must be accompanied by a regulatory framework that provides flexibility in electricity systems

In response to the increasing integration of variable renewable energy sources, it is essential to implement appropriate regulatory measures to enhance system flexibility. On the supply side, these measures should incentivize the integration and full utilization of the available flexibility of generators, establish adequate price caps to encourage the integration of storage technologies and flexible plants in wholesale markets, and improve ancillary service markets. On the demand side, they should enable consumers to be more responsive to price signals and promote the implementation of demand response programs. A key challenge lies in designing a long-term market that fosters the development of infrastructure to support investments in new plants that provide flexibility and storage. This can be achieved through capacity and/or flexibility markets.

Policy Consideration 7. Limited intervention in the design of wholesale electricity markets helps to maintain investment incentives

Interventions in electricity markets in periods of stress and where prices tend to increase should focus on maintaining the purchasing power of the most vulnerable households, be temporary, and promote energy efficiency, while maintaining a stable regulatory framework that does not discourage investors. Unforeseen changes in regulations negatively impact the financial viability of energy projects. These measures may erode investor confidence in the regulatory framework, thereby increasing the perception of risk and the cost of obtaining financing. This cost increase can hinder progress towards a more sustainable economy, slowing down the process and increasing the costs associated with the energy transition.

Policy Consideration 8. Greater emphasis should be placed on regional integration as a strategy for resilience to periods of stress, such as variability in water generation or increases in electricity demand

The creation of regional electricity markets can facilitate the more efficient use of energy resources and transmission infrastructure, minimizing reliance on additional reserves and possibly avoiding or delaying the need for new generation investments. It is essential to strengthen projects such as the Central American Electrical Interconnection System (SIEPAC), as well as to promote the consolidation of projects such as the Andean Electrical Interconnection System (SINEA), which aims to connect Bolivia, Colombia, Chile, Ecuador, and Peru; the Southern Cone Energy Integration System (SIESUR), which integrates Argentina, Brazil, Chile, Paraguay, and Uruguay; and the Northern Arc, which seeks to integrate Guyana, Suriname, and French Guyana with Brazil. These initiatives are essential to improve energy security and move towards the decarbonization of the region's electricity matrix.

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2 INTRODUCTION

INTRODUCTION

The three pillars for the development of the electricity sector are affordability, supply security, and environmental sustainability. These goals, essential to any energy policy, benefit from short-term prices that provide adequate signals for efficient economic dispatch. In addition to making electricity prices affordable for consumers, they must also send the right signals to the market and ensure cost recovery by providing incentives for investments that guarantee future generation capacity and the expansion of electricity transmission infrastructure. Furthermore, it is crucial that these prices encourage the transition to renewable energy sources, thus contributing to environmental sustainability.

The issue of electricity spot prices has recently become a top concern for governments because of two major events. The first is the sustained increase in short-term electricity prices that have been passed on to electricity tariffs in different regions of the world, which has eroded household purchasing power and impacted the competitiveness of energy-intensive industries. The second is the appearance of spot prices close to zero or negative prices in some markets with a high penetration of renewable energies.

Europe, hit by the increase in natural gas prices, is a clear example of the first event; Latin America and the Caribbean have also experienced similar situations. Governments have reacted by implementing various measures—tax cuts, price freezes, transfers to vulnerable groups, windfall profits taxes—to cushion the economic impact on the population.

Beyond these short-term solutions, these price increases have led to a profound debate on the need to adjust market designs in the electricity sector. The ultimate goal is to achieve prices that are affordable for the end consumer and less dependent on the volatility of fossil fuels, as well as to protect consumers from future electricity price increases and accelerate the penetration of renewable energies.

The design of electricity markets is crucial to understanding price dynamics in the sector. This design influences investment decisions, the composition of the electricity matrix, and the behavior of market participants. Although the price paid by the end consumer is the retail price, its variability is mainly due to wholesale electricity prices. This is why studying wholesale markets, including their most important submarkets—the short and long term—is key to understanding price dynamics. The former, which is the central focus of this paper, is crucial to provide adequate price signals to facilitate the efficient operation of electricity generation resources and to inform and encourage investment in the sector.

Economic efficiency in the operation of liberalized wholesale electricity markets depends on market designs that encourage efficient short-term price formation and send the right signals to market participants. This gives rise to the following question:

> Which elements of the current regulatory framework increase the economic efficiency of short-term markets, and which ones inhibit them?

Globally, there is a trend towards the adoption of bid-based markets with greater spatial and temporal granularity. Nevertheless, in the Latin American and Caribbean region, there is a clear preference for cost-based markets and, in some cases, for zonal and single-settlement markets. This choice, rooted in a specific historical and socio-political context, leads us to ask what regulatory changes can be implemented in the region's electricity markets.

The challenge lies in thoroughly understanding the fundamental characteristics of these markets and the factors that influence short-term price determination, whether related to the design of the market itself, the electricity infrastructure, or external factors. This paper seeks to outline the most relevant elements of short-term electricity market designs in Latin America and the Caribbean. We analyze and contrast short-term wholesale market models in the region, offering an updated perspective on trends, challenges and possible reforms.

In regions such as Latin America and the Caribbean, although short-term markets play a secondary role in determining final electricity prices or electricity tariffs, understanding them is a first step in deciphering the structure and functioning of wholesale electricity markets. Although market rules have been modernized in some of the region's markets, there are opportunities to increase efficiency in the operation of the market in the short term, including making electricity dispatch more efficient through prices that better reflect supply and demand conditions, establishing effective market and regulatory mechanisms to ensure long-term resource adequacy, and implementing strategies capable of mitigating market power.

As part of the energy transition, one of the most pressing challenges is to replace thermal plants, which have high marginal costs linked to fuel prices, with power plants with high initial investments, but with practically zero marginal costs and lower CO_2 emissions, as in the case of solar and wind energy. Integrating these sources into the electricity matrices introduces new challenges in the market structure. These challenges include the need to adapt the market to maintain investment incentives, considering the intermittency of renewable energies and the flexibility required by each system. **A well-defined pricing system is essential to guarantee an energy transition with a high integration of renewable sources, ensuring an efficient economic dispatch and lower associated costs.**

On the other hand, although the recent spike in electricity spot prices has been linked to the increase in gas prices, **there are other factors contributing to volatility.** For example, dependence on hydropower in certain countries can cause price increases during periods of drought. Other exogenous phenomena, such as short-term demand shifts and extreme weather events, also play a crucial role in these dynamics. It is important to identify these factors that influence short-term price increases in electricity markets to design markets that maintain efficient operation, encourage the use of lower-cost resources, and promote environmental sustainability.

Other regions, such as Europe and the United States, are already in the process of **reforming their short- and long-term wholesale markets** to manage short-term electricity price increases more effectively, while maintaining regulatory elements that have proven to be effective, such as merit-based dispatch and marginal cost remuneration. Given that in Latin America and the Caribbean there are also several reforms under analysis, it is necessary to identify, for each market, which elements have worked, and which have not; as well as to identify which are the best practices in developed countries, in order to consider them in the electricity markets of the region.

The rest of this paper is structured as follows. Section 3 discusses the factors that determine price formation in short-term electricity markets. This section includes a comparison between the main regulatory elements of the short-term markets in Latin America and the Caribbean and the most important markets in the United States and Europe. Section 4 focuses on the main discussions on possible regulatory changes in wholesale markets in Europe in recent times and reviews some of the main shortcomings in market designs and proposed solutions. Section 5 shows the characteristics of the short-term market design in eight Latin American and Caribbean countries, explains its features and discusses the factors that determine short-term electricity prices. Section 6 reflects on market practices that could be adopted by the region, inspired by the experiences of the main electricity markets in the United States and Europe, in the context of an energy transition.

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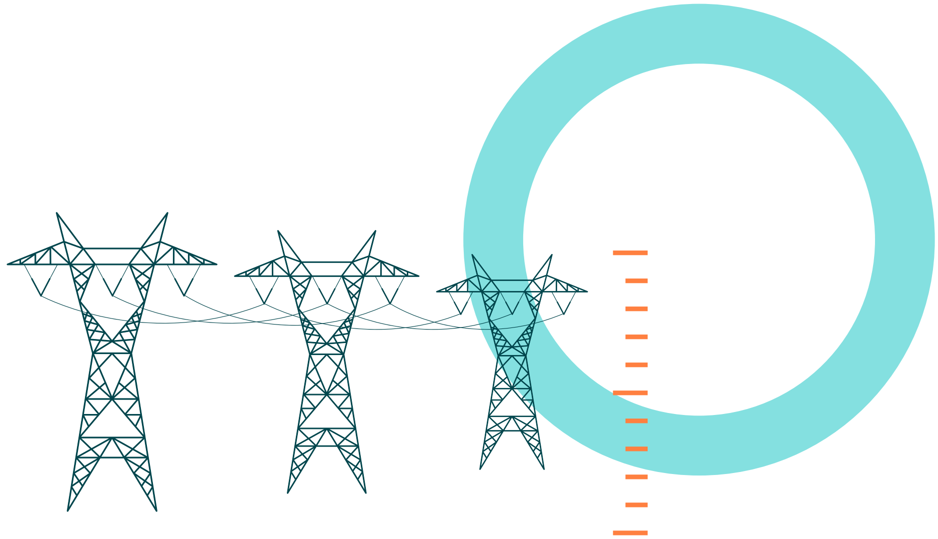
3

SHORT-TERM ELECTRICITY PRICE DYNAMICS



3

SHORT-TERM ELECTRICITY PRICE DYNAMICS

One of the main challenges faced in the design of electricity markets is to solve the so-called energy trilemma: **the electricity sector must provide a source of energy that is affordable, secure, and environmentally sustainable.**[5] The conjunction of these three elements is a fundamental pillar in country-wide economic development processes.

Electricity is a fundamental input and resource for the modern economy.

Any variation in its prices can significantly affect all consumers. The impact of an increase in electricity prices is evident in household and government budgets, in the competitiveness of companies, and, therefore, in the price structure in an increasingly interconnected and competitive global market. Hence, it is important that electricity prices accurately reflect short-term supply and demand conditions, avoid distortions, and send appropriate signals to the market.

Over the last few years, energy prices became more relevant, due to a significant increase in the prices of short-term wholesale electricity markets globally, which in many cases were reflected in electricity bills, mainly in Europe. This phenomenon has been largely driven by an increase in the price of energy commodities, such as natural gas and coal. It was against this backdrop that discussions began in Europe on a potential reform of electricity markets, to make business and consumer energy bills more independent of the short-term market price of electricity.

Discussions about the design of short-term electricity markets are not new, but with the increasing incorporation of renewable sources into electricity grids, the pricing structure has undergone a significant transformation. This new dynamic contrasts with the traditional trend observed in electricity systems predominantly based on dispatchable plants, whether thermal or hydroelectric. The adoption of variable renewable energies (VREs), such as solar and wind, has resulted in lower average prices and greater price volatility in the markets. The adoption of new technologies

[5] Energy security is defined as the ability of a country or region to meet its energy demand reliably and sustainably. This involves the efficient management of primary energy resources, both domestic and international, the protection of critical infrastructure, and suppliers' ability to meet current and future energy needs. Affordability implies that energy prices are accessible to all consumers. Environmental sustainability focuses on energy efficiency in terms of supply and demand, and the development of an energy supply from renewable and low-carbon sources (WEC, 2023).

triggers technical discussions around designing markets that efficiently integrate VREs.

In Latin America and the Caribbean, the causes of short-term electricity price increases vary among countries, especially due to the composition of their electricity matrices. While the predominance of hydropower in many countries in the region means that adverse climatic phenomena (such as droughts) play a determining role in short-term price behavior—since, if hydropower generation capacity is affected, prices can increase substantially—it is also important to consider dependence on fossil fuels. In countries that do not produce natural gas, oil or coal and depend on imports, electricity prices are subject to external shocks associated with the cost and availability of these inputs. Therefore, the production or import of fossil fuels such as natural gas, oil and coal significantly influences the volatility of spot electricity prices in the region.

Electricity price formation processes respond to multiple factors, due to the heterogeneity of electricity systems and market designs across different countries. Some proposals regarding the management of price increases advocate for structural reforms in price formation methods in wholesale electricity markets, while others propose direct interventions, such as the implementation of subsidies or the reduction of energy taxes, to cushion the impact of high energy prices on economic activity.

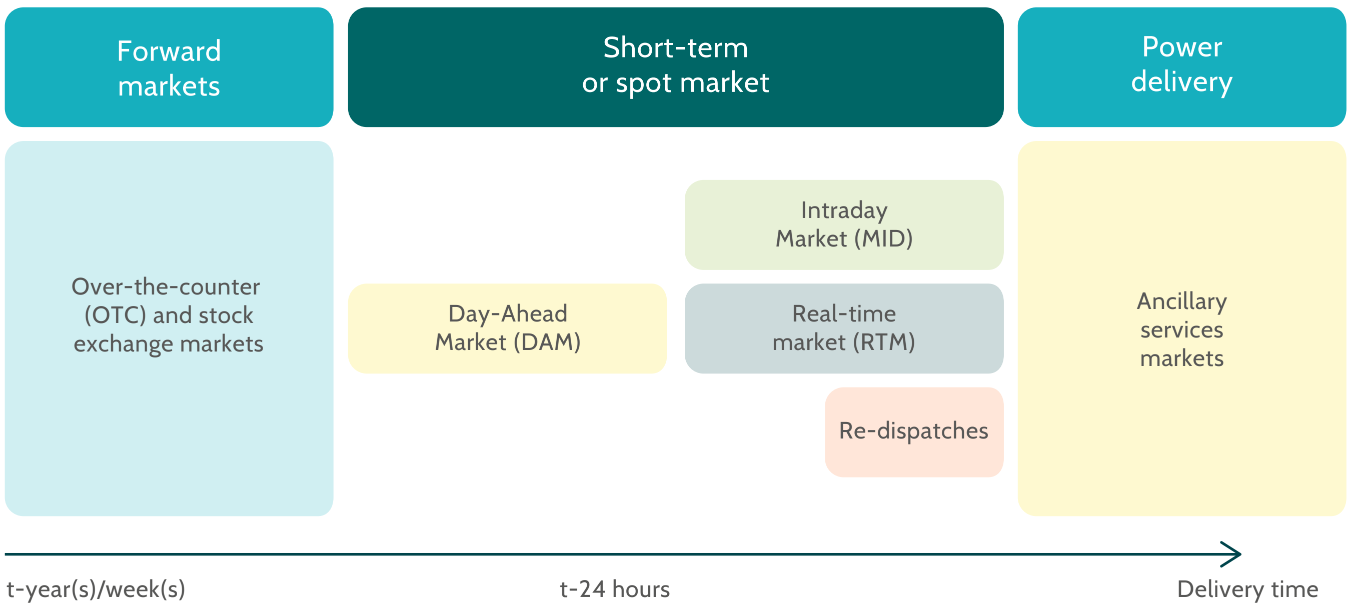
Identifying the main factors that affect prices is a first step to proposing regulatory improvements that can be implemented in the markets in the short term, thus ensuring more competitive electricity prices and a more efficient and transparent electricity dispatch.

It is important to differentiate between wholesale and retail electricity prices in liberalized markets. A wholesale electricity market is an organized system where electricity generators and purchasers transact for either the sale or purchase of electricity in bulk. For example, a generator that, connected to the transmission grid, sells its electricity to entities such as electricity distribution companies. Wholesale prices are those paid by buyers in this market.

Multiple submarkets have developed within the wholesale markets, each with its own characteristics and prices. These include short-term markets (or spot markets), long-term markets, ancillary services markets, and capacity markets, among others. Figure 1 shows an overview of the main components of the wholesale electricity markets. Short-term or spot markets balance the short-term supply and demand for electricity and are widely used to adjust long-term positions in periods close to the delivery of electricity. Similarly, the prices of these markets are used as a reference in long-term markets and other submarkets.

In liberalized electricity markets, the short-term market is usually open and competitive; its prices respond to a series of institutional, exogenous, and infrastructure-related factors (see Figure 2). Although the electricity matrix (the set of energy sources used) largely determines wholesale price dynamics, this matrix is also influenced by the factors mentioned above. For example, in a market dominated by thermal generation, spot prices can be greatly affected by external factors such as fuel price dynamics. Transmission constraints may also exacerbate price increases if the infrastructure does not allow for efficient distribution of the power generated to consumption centers.

FIGURE 1. **Example of the main submarkets in wholesale electricity markets**



Source: Prepared by the authors based on Ahlqvist *et al.* (2022) and Ribeiro *et al.* (2023).
Note: Forward markets operate over periods ranging from years to weeks prior to the actual delivery of electricity and are divided into two main types. On the one hand, over-the-counter (OTC) markets stand out for their high flexibility, allowing the parties involved to design contracts tailored to their needs. On the other hand, stock exchanges reduce credit risk for market participants by implementing a central clearing house (CCP), which acts as a central counterparty, and facilitate trading of standardized products or derivatives. In these markets, the underlying prices of forward power contracts are based on short-term prices. Although most countries have day-ahead markets, in some they are not financially binding, and prices are set ex post or ex ante.

Long-term markets play an important role in many countries in Latin America and the Caribbean, and generally concentrate the main electricity trading activity in wholesale markets. In addition, the need to ensure the reliability of electricity supply in the short and long term has driven the creation of specialized markets in certain countries, including ancillary services[6] and capacity markets.[7]

In wholesale markets, retail energy suppliers purchase electricity for sale to end customers. Retail prices are those paid by the end consumer, such as households or businesses that are connected to the distribution network. Aside from the cost of the energy itself, these prices generally incorporate the costs associated with electricity transmission, distribution, and sale. Retail price composition is usually subject to stricter regulations, which limit its volatility and ensure affordability for end consumers.

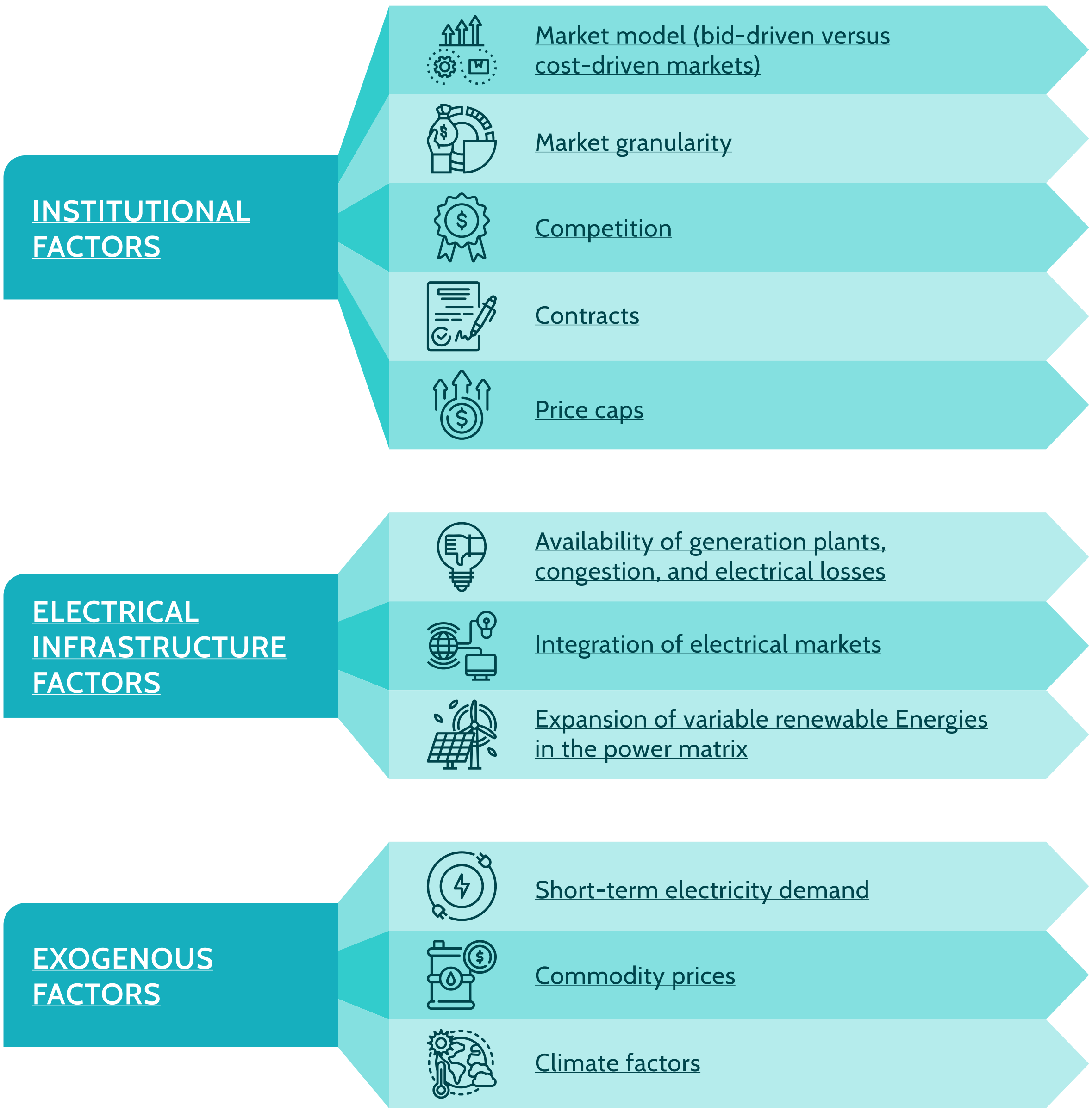
This study will focus on short-term market prices, since their greater dynamism and lesser regulation allow for a more in-depth analysis of the factors at play. It should be noted that any changes in wholesale prices may have an impact on retail prices. The degree of this impact, however, will depend on two main factors: the volume of electricity traded in the short-term market and the degree of influence that this market exerts on the other submarkets. In this paper, we will use the terms "electricity market" or "electricity price" to refer specifically to short-term electricity prices or markets.

This section describes the main factors involved in determining electricity prices in short-term markets. The section will lay the groundwork for the following chapters, in which we will review recent developments in Europe and Latin America and the Caribbean. We will also address proposals for improvements in the wholesale markets that, depending on each context, could be implemented so that electricity prices correctly transmit signals to all market participants, from consumers to companies.

[6] These markets operate in parallel to the short-term energy markets and allow the management of supply and demand imbalances. Their main task is to regulate the frequency and prevent voltage drops. Here, generators offer part of their capacity to meet unforeseen variations and guarantee the continuity and quality of the electricity supply.

[7] The primary goal of these markets is to reinforce long-term reliability by ensuring that there is sufficient generation for future demands. Unlike short-term markets that remunerate actual production, capacity markets compensate generators for their promised potential capacity. Generators whose bids are accepted in this market receive market-based payments for their capacity, in addition to payments for supplying energy and ancillary services, at prices also determined by the market.

FIGURE 2. Factors influencing short-term electricity prices



Source: Prepared by the authors.
Note: The figure shows the main factors that influence electricity market prices and classifies them into three categories. Institutional factors include the rules and regulations that dictate the operation of the electricity markets. Electric infrastructure factors are inherent to internal market operation mechanisms. Finally, exogenous factors are those variables that, although they affect energy prices, are unrelated to the intrinsic operation of the electricity markets.

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3.1 Institutional factors

The current design of electricity markets is the legacy of the sector reforms implemented in the 1990s, which sought to increase efficiency, promote competition, and attract investment. These reforms brought about three fundamental structural changes (Foster & Rana, 2020; Schmalensee, 2019). First, the figure of the vertically integrated electricity company—in which a single entity oversaw all the processes associated with electricity supply—was dismantled. Instead, entities dedicated to specific functions for each market segment emerged. Second, they opened the door to private sector participation,[8] especially in the electricity generation and distribution/commercialization segments,[9] and established wholesale electricity markets, thereby abandoning monopolies and fostering competition in the sector.[10] Finally, in terms of regulation, the most significant measure was the creation of autonomous entities, such as independent market operators and regulators, in charge of coordinating these emerging markets.

In general terms, this was a process of deregulation and promotion of competition that resulted, in many cases, in a significant improvement in the efficiency of the sector (Davis & Wolfram, 2012; Cicala, 2015; Balza *et al.*, 2020; MacKay & Mercadal, 2023).

Reform processes in wholesale markets have varied from country to country and have been adapted to the specific circumstances and needs of each region. In these liberalized markets, short-term electricity markets were created to improve the efficiency, reliability, sustainability, and competitiveness of the electricity sector. For example, these short-term markets allow for necessary adjustments due to differences between what was projected—such as demand and hydrology—and what actually occurred. Without these adjustment mechanisms, the markets would be very rigid, making it difficult to respond to variations and contingencies in the electricity sector.

The main characteristics that have a direct influence on price formation mechanisms in short-term markets include auction methods, price granularity, the level of competition in the markets, contracts, and price interventions. The following subsections review each of these factors and present a discussion of their influence on short-term price levels.

3.1.1. Bid - versus cost-based markets

Since electric power is a very expensive commodity to store, a constant balance between generation and demand is required. While short-term demand is presented exogenously and tends to be inelastic, it is the design of electricity markets that determines how supply curves are structured.[11] In the markets, electricity dispatch is the mechanism that determines the order in which each power plant injects its energy into the grid during a specific period. This process prioritizes efficiency, so that the cheapest unit generated is the first to inject its energy into the grid. This description is a simplification, however, since in practice the electricity dispatch must consider several additional constraints and conditions. These include power plant operating constraints (such as start-up and shutdown times, ramp rates, and technical minimums), transmission limits in the power grid (which may limit the flow of power between different zones), and reserve requirements to ensure the reliability and stability of the power system.

[8] In regions such as LAC, one of the main motivations behind the restructuring of electricity markets was to attract the private sector to all segments of the industry. This occurred in a context where there was limited investment in the sector with a growing demand for electricity (Wolak, 2003).

[9] Unbundling generation and transmission are a key measure to ensure competition in wholesale electricity markets. This measure prevents undue advantages from being granted in these markets.

[10] The theory argues that if competitive market mechanisms are properly designed and there are no abuses of market power, power generators, when competing, should be incentivized to optimize their costs, ensure capacity to meet demand, seek innovations, and invest to enter and withdraw from the market in order to minimize expected losses (Joskow, 2019). The development of effective competition faces numerous challenges. For example, considering the inelastic nature of demand in wholesale energy markets, situations where demand is at a maximum and all available capacity is used allow the exercise of market power, by restricting supply, to cause considerable price fluctuations (Schmalensee, 2021).

[11] For a detailed description of how electricity markets work, see Annex A.

The electricity operator decides the quantities that each plant must inject into the grid and is, therefore, in charge of maintaining the balance between system supply and demand, considering all these constraints. The operator considers the aggregate supply curve—the audited bids or costs of the power plants—required to meet system demand, along with operating and transmission constraints to determine the equilibrium price and dispatch quantities of each generator.

Figure 3 displays a merit order dispatch configuration, where electricity generated from different technologies is usually dispatched based on market demand. In general, wind and photovoltaic plants are the first to dispatch, given the nature of their near-zero marginal costs, while thermal plants are the last, as their marginal cost is mainly determined by fuel costs. Hydroelectric power plants also play a crucial role in this pecking order, but their treatment varies according to the type of plant. Run-of-river hydropower plants are treated similarly to wind and solar, as they have marginal costs close to zero and generate electricity according to the natural flow of water without significant storage capacity. In contrast, reservoir hydropower plants usually factor the opportunity cost of stored water into their dispatch decisions. This means that the dispatch of these plants considers the future value of water, especially in scenarios of possible droughts, as well as the expected prices of other fuels such as natural gas or coal. This consideration adds complexity to the calculation of its marginal cost. As a result, in countries with a high proportion of hydroelectric generation, dispatch mechanisms are more complex and are not based solely on the immediate marginal cost of hydroelectric power.

The configuration of the supply curve varies according to the composition of each country's generation portfolio. Systems where thermal generation predominates have lower price variability compared to systems with a high proportion of renewable sources. Considering Figure 3, as an example, in a low demand scenario, the marginal cost could converge towards the lower limit of zero, oscillating in a range that could reach up to US$ 180 per MWh. Conversely, in a country whose energy portfolio is mainly composed of thermal plants, although price volatility may be more contained, average prices are likely to be comparatively higher.

In addition, with respect to Figure 3, the initial analysis of how prices are formed should focus on the design of the electricity market. The way the market is conceived dictates the ground rules for participants in the electricity markets and establishes the conditions under which energy is dispatched, the priority criteria, and the economic interactions between electricity generators and buyers.

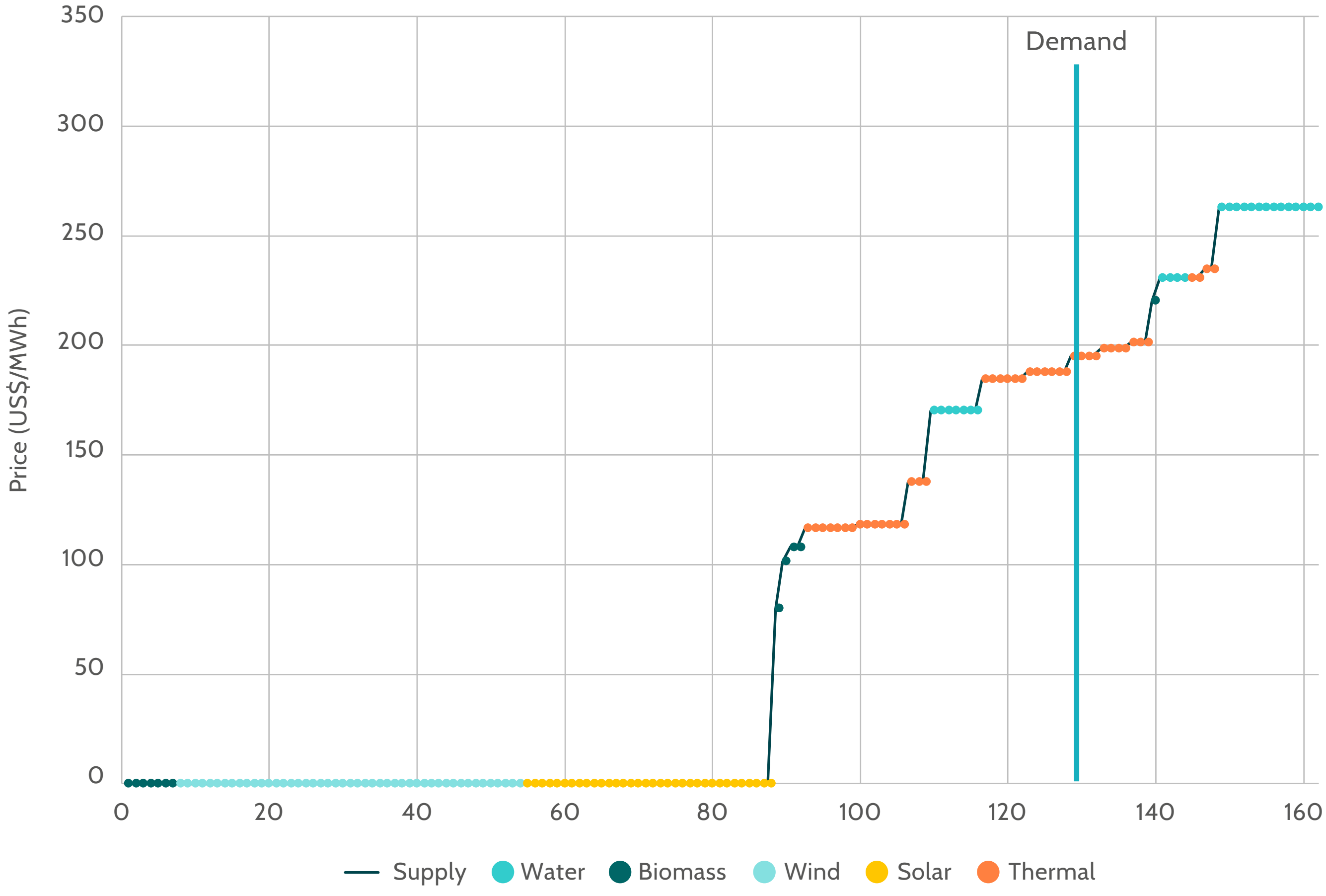
There are two major designs in this regard:

- **Bidding or auction-based market,** where generators submit price and quantity bids in a wholesale market auction.
- **Cost-based market,** where these proposals are audited by the regulator.

In cost-based markets, electricity dispatch is centralized. The market operator analyzes in detail the bids of the generating plants and relies on information from the participants' bids to determine both the prices and the quantities of electricity generated by each plant. This approach appears mainly when there is a lack of confidence on the part of the regulator that the participants are acting competitively.

This concern is particularly relevant in several Latin American and Caribbean countries. In these electricity systems, market concentration in a few electricity generation companies has raised concerns about the possibility of price and quantity manipulation in bids. In markets with high state participation, there is also a risk that public companies may submit bids that distort the market, affecting the efficient operation of the dispatch.

FIGURE 3. **Electricity supply and demand curves**



Source: Prepared by the authors based on data from Uruguay's Administración del Mercado Eléctrico (ADME).
Note: The figure illustrates the electricity supply and demand of the Uruguayan wholesale market at 6 p.m. on January 27, 2023. The day was selected for illustrative purposes only. The sky blue line represents demand, while each dot indicates the marginal or variable cost of each generating plant. Costs are shown by type of generation source and are ordered from lowest to highest, so that the most efficient plant (in terms of costs) is the first to inject its energy into the grid. The price is set where the supply and demand curves intersect.

The bid-based market is predominant in wholesale electricity markets in Europe and the United States, while cost-based markets are predominant in Latin American countries where hydropower has a strong presence, such as Brazil, Chile, and Peru. This method is not limited to this region, however; it is used in the United States and Ireland when the regulator identifies local market power, and is adopted during redispatch in some European electricity markets (Ahlqvist, Holmberg & Tangerås, 2022; Munoz *et al.*, 2018). From an economic point of view, one of the main drawbacks of cost-based markets is that—although the exercise of monopoly power by market players is quite restricted—operators play an essential role in marginal cost estimations. This cost assessment can be complicated, as is clear from the marginal cost calculation for hydroelectric power plants, which is often a source of dispute between generators and regulators (Fischer & Serra, 2000). The price of water stored in a dam is normally determined by future rainfall expectations, current dam levels, future plant plans, and the expected marginal costs of thermal plants.

An advantage of cost-based markets over bid-based markets is their predictability in electricity spot prices. By eliminating fluctuations arising from supplier offers, these markets could reduce the uncertainty and cost of entering into forward contracts. As a result, market participants can project future prices using public data and the cost-based dispatch algorithm (Wolak, 2003).

Bid-based markets can be organized in a decentralized or centralized manner (Ahlqvist, Holmberg & Tangerås, 2022; Pollitt *et al.*, 2022).

In a decentralized system, each plant decides how much electricity it wants to produce in the day-ahead market (DAM),[12] according to contractual obligations, market prices, and other internal and external conditions. The logic behind this organization is that, when it comes to deciding, agents are better informed than a central authority. Electricity markets in Europe are decentralized in the sense that producers are allowed to use auto-dispatch in the day-ahead market. In these markets, transactions are carried out on fifteen power exchanges (PXs).[13] Market participants are able to trade electricity in these spaces (Herrero, Rodilla & Batlle, 2020). The management of the electricity system is separated from the market, remaining under the supervision of the transmission system operators, who guarantee the reliability of the system. Under this decentralized approach, market participants are expected to take a more active role in the efficient management of generation resources and in clearly and simply communicating their needs to buy or sell energy. Bids are generally based on prices and quantities made by sellers, although in reality there are a number of more complex bid formats, such as block bids.

In markets with a centralized system, the operator is responsible for the operation of all short-term markets and relies on the information provided by producers about their costs. Based on this information, the operator decides how much each generation unit should produce for the day-ahead market. Major U.S. electricity markets, including PJM, ERCOT, MISO, and CAISO, operate under a centralized dispatch system. In these markets, participants submit their bids, which include the marginal cost, their fixed cost (e.g., per hour), and the plant's start-up costs. In the case of cost-based markets, centralization goes beyond the dispatch decision; operators are tasked with auditing marginal generation costs.

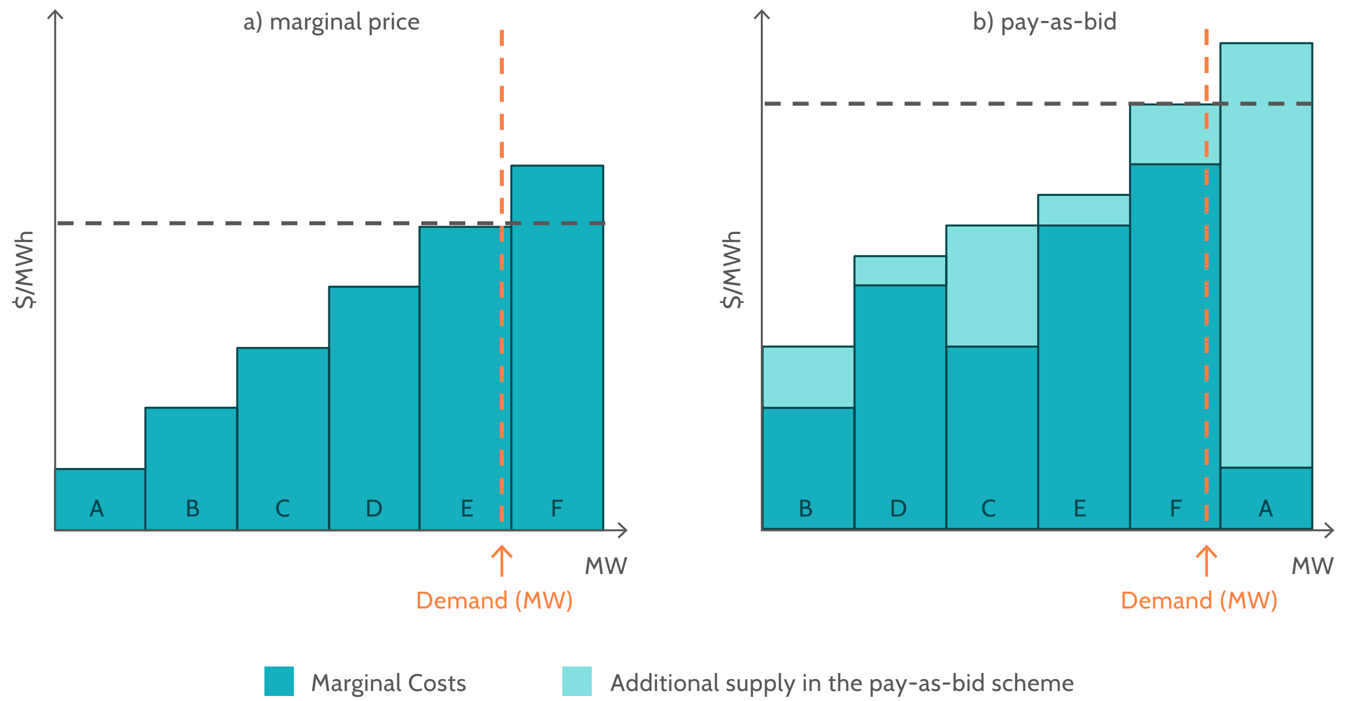
There are two types of pricing rules in markets, either bid-based or cost-based.

On the one hand, there is the marginal price scheme or uniform price auction, used in most electricity markets. Under this method, all market participants receive a payment based on the marginal cost of the market. On the other hand, in the pay-as-bid market, generators receive a payment exactly equal to the bid they submitted. Figure 4 displays the dispatch mechanism using marginal price and pay-as-bid schemes. Bids are dispatched in order of merit, according to the prices submitted by the bidders.

[12] Many power markets operate based on transactions agreed upon a day ahead and are known as day-ahead markets due to the start-up times required by some types of power plants.

[13] A power exchange is an entity that provides a spot market for trading electricity in an intra-day or day-ahead market.

FIGURE 4. **Dispatch under marginal price and pay-as-bid schemes**



Source: Prepared by the authors based on Tierney, Schatzki & Mukerji (2008).
Note: The orange line indicates demand in both cases. Participants' bids are indicated by the letters A-F. Accepted bids are those before the demand. In the marginal price scheme (a), participants receive the market price and thus have a profit margin. In the pay-as-bid scheme (b), participants receive their bid price. In the pay-as-bid scheme, stakeholders can adopt strategic behaviors by increasing their price proposals in order to maximize their profits. This behavior may result in a suboptimal economic dispatch and a rise in equilibrium prices.

Based on various studies, the following advantages can be established for the marginalist remuneration scheme (Cramton, 2004; Oren, 2004; Ren, 2004; Tierney, Schatzki & Mukerji, 2008):

- **The profit margin** available to participants in this scheme—the difference between the bid and the market equilibrium price—provides a means for them to recover part of their fixed costs.
- **The scheme motivates generation plant efficiency and performance improvements,** since bidders have an incentive to disclose their real marginal costs. This makes dispatching efficient.
- **The marginalist scheme is not only an efficient model,** but also a fair one, because all winners—i.e., accepted bids—pay or receive the same price, and those who bid outside the accepted bid curve are not dispatched, because they do not receive/pay a price they were not willing to sell/buy at.
- Unlike the pay-as-bid mechanism, the **marginal pricing scheme reflects the generation capacity surplus or deficit** and sends economic signals and incentives to potential investors in the generation segment.

As for the disadvantages or difficulties of the marginalist method, we can detail the following:

- **A potential problem with this scheme is that whenever a bidder can influence the price,** it will have the opportunity to exercise market power by bidding above its marginal cost. This situation is exacerbated when a bidder owns several generation plants or technologies. It can manipulate the market price by adjusting the supply of one of its units, which allows it to earn additional profits on all its plants that receive the marginal market price. This opportunity to exercise market power can be mitigated if market regulation establishes that bids must be cost-based and auditable by the market operator.
- **In countries with a high percentage of hydroelectric generation,** given the flexibility of hydropower plants, market players can influence prices during periods of scarcity or when available generation is reduced.

In the pay-as-bid method, generators are remunerated according to the price they bid, so the market price is independent of the marginal technology. This method creates incentives for plants—especially those with a marginal cost close to zero—to bid prices above their marginal cost to recover their costs, but also below the price of the last dispatching plant. This means that participants who possess information about the different bids, if any, can benefit from this system.

The following are some of the features of the pay-as-bid scheme (Haghighat, 2012; Kahn, 2001; Willems & Yu, 2022):

- **In the most basic pay-as-bid scheme, efficiency may be lower than that obtained in a marginalist systema.** This is because generators have no incentive to submit bids that reflect their variable costs. Instead, they are forced to submit bids that are close to the cost or price of the most expensive generator needed to meet demand. There is therefore no guarantee that lower prices will be obtained compared to those of a marginalist model. In addition, there is a risk of distorting the economic dispatch.[14]
- **In the merit order dispatch model, some bids with lower marginal costs will not be accepted,** because they present higher prices than those of some plants with higher marginal costs that would have presented bids with more conservative prices.
- **The scheme introduces an increase in energy price volatility and makes** it difficult to forecast prices in the short and medium term, in addition to the fact that the profitability of the plants will depend heavily on a successful forecast.
- **The pay-as-bid method does not reflect the existence in the market of a surplus or deficit of generation capacity** and, in the long term, does not transmit clear economic signals to potential investors.

One possible version of the pay-as-bid scheme is for generators to bid based on their total costs, according to an expected or historical plant factor. With this scheme, the total costs of fully amortized conventional thermoelectric plants will be basically those related to fuel costs; therefore, these plants may appear more economical than a new nuclear or hydroelectric plant with high unamortized investment costs and very low variable costs. This would distort the dispatch without any economic sense.

[14] Annex A provides a comparative analysis between the application of variable costs and total unit costs in energy dispatch and capacity expansion. This analysis shows that the use of variable costs is more effective in terms of efficiency.

3.1.2. Pricing granularity

When designing electricity markets, a key distinction apart from the way in which the supply curve is constructed, is the granularity with which these markets operate and prices are formed, which can vary in both spatial and temporal dimensions.

Short-term wholesale markets may present different levels of segmentation or granularity in their spatial dimension: 1) local marginal pricing model (LMP); 2) zonal pricing model; and 3) single price models.

The main difference between them lies in how the pricing system reflects the limited capacity of the transmission networks.

Zonal or single zone pricing models have been implemented throughout the entire European Union (UE)[15] and in certain countries in Latin America and the Caribbean. In this scheme, a single market price is established at defined time intervals for the entire zone or subzones in question. The initial assumption underlying zonal markets is that the power grid system's transmission capacity is infinite, and only recognizes the existing restrictions between zones. In practice, however, transmission networks have physical limitations that can lead to congestion when the demand for electricity transfer exceeds the available capacity.

To manage these congestions and maintain the safety and reliability of the electrical system, redispatching is performed. Redispatching is a process whereby transmission system operators (TSOs) adjust the initial generation dispatch, increasing production at some plants and decreasing it at others, in order to respect transmission constraints (Antonopoulos ***et al.***, 2020). This dynamic can motivate the most expensive plants to maximize their profits by offering considerably high prices, compared to those that would be established in a nodal market. Such a process generates additional costs, as it may involve the use of less cost-effective generators and compensation payments to the affected generators. This behavior may result in an increase in electricity prices in short-term markets.[16] These efficiency losses emerge as a consequence of not adequately recognizing electricity transmission constraints in the zonal pricing model (Eicke & Schittekatte, 2022). This reality led to the conception and development of an alternative approach, the LMP, or local marginal or nodal pricing model.

The LMP model assumes that transmission capacity is not infinite and establishes a price for each node of the power grid, based on supply, demand, electricity losses, and costs due to transmission constraints associated with each node. In other words, the LMP model recognizes that location is an important aspect of electricity and that it should be reflected in each electricity node (Chao & Peck, 1996; Schweppe *et al.*, 1988). This mechanism models the characteristics of the transmission network, including security constraints, and results in nodal prices, which reflect the cost of energy determined by the constraints due to network limitations.

LMPs provide a more accurate and realistic picture of the underlying economics of electricity transmission and allow for a more efficient allocation of resources in the sense that costly redispatches are avoided. This model also provides an incentive for investments in transmission infrastructure, which improve the efficiency of the system as a whole (Eicke & Schittekatte, 2022). This more sophisticated and accurate framework results in a more reliable representation of the operational and economic dynamics governing electricity transmission systems today.

[15] EMost European Union countries have a single electricity supply zone, which coincides with each country's territorial boundaries. Some countries, however, have multiple supply zones within the geographic boundaries of the country in question. For example, Denmark is divided into two supply zones, while Italy has six, Norway has five, and Sweden has four.

[16] In the context of greater integration of variable energies such as solar and wind, grid restrictions impose a lower use of these renewable sources and therefore potentially higher prices.

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The LMP model, by explicitly considering the structure of the transmission network when determining dispatch levels, both internally and between regions, can greatly increase the volume of interregional trade.

Nodal price signals, due to their ability to accurately reflect local conditions, tend to be inherently more volatile in the short term compared to zonal prices (ENTSO-E, 2021). The implementation of hedging mechanisms to mitigate nodal price volatility can be more complicated if there is low liquidity in the market. This is because there is a restricted number of trading partners at each node (Eicke & Schittekatte, 2022).

The literature indicates that, although zonal prices tend to be more stable than those of the nodal system, the risk of cost overruns related to the redispatch market is evident in them. In reality, the effectiveness and challenges of each system are determined by the priorities established in the electricity markets. Table 1 shows the main benefits and challenges of each system.

TABLE 1. Benefits and challenges of different types of spatial granularity

Granularity	Benefits	Challenges
Nodal	» Efficient generation dispatch » Long-term local signals/incentives for investments » Redispatch is not necessary	» High complexity of the system » Many small submarkets with possible low competition and abuse of market power » Fluctuating local prices
Zonal	» Small number of different prices » Increased intrazonal competition » Price stability	» Reduced flexibility signals » No local signals/incentives for long term investments » Difficult to determine zonal boundaries » Potential high redispatching costs and reallocation problems » Difficulty in defining adequate remuneration for redispatching services
Unique	» High market liquidity » Low complexity of the system » Relatively high competition » Price stability	» Possible inefficiency of long-term investments » Potential high redispatching costs and reallocation problems

Source: Heffron *et al.* (2022).

Temporal granularity of markets

Settlement structures in the electricity markets are the fundamental mechanism through which short-term transactions are cleared.

They can be classified into two main categories: single and multiple settlement.

In the single settlement model, there is a single short-term market in which all transactions are cleared and settled according to a single determined market price. This model is used by most Latin American and Caribbean countries. The simplicity of this approach facilitates operation and reduces administrative complexity but may limit the flexibility of participants to adapt to changes in demand or generation.

The multiple settlement model involves at least two short-term markets: on the one hand, the day-ahead market (DAM); on the other hand, the intra-day market (IDM) in Europe or the real-time market (RTM) in the U.S. wholesale markets.

The DAM determines the prices known as next day prices. This prospective market functions as a space in which, on a specific day (t), the price for the energy to be delivered the following day is established (t+1). In this market, participants submit bids daily for every hour or even every half hour of the following day. This space establishes the equilibrium prices that determine the quantities that each participant will buy or sell. As electricity markets face changing demands on the day of operation, IDM and RTM emerge. These markets are intended to provide participants with some flexibility, so that they can adapt to unforeseen situations that arise after the closing of the DAM. These mechanisms are activated in the interval between t and t+1 and allow agents to rectify their positions in the face of unforeseen variations or changes in initial projections. In addition, they provide the system operator with the tools to make essential last-minute adjustments and thus ensure the safe and efficient operation of the power system.

Prices and quantities in the DAM represent financial commitments, and the subsequent markets—IDM/RTM—only set prices for increases/decreases with respect to the immediately preceding market. Thus, market participants can change their positions according to the updated information and the system operator is able to maintain the security of the operation.

DAM and IDM prices are usually established ex ante, i.e., prior to the energy dispatch. In RTMs, however, pricing can be performed both ex ante and ex post.

The single settlement model, used in Latin America and the Caribbean in countries such as Brazil, Chile, and Colombia, is characterized by the possibility of fixing electricity prices before or after dispatch. In the case of Brazil, prices are established for each of the four zones one day before dispatch (t) and are calculated on an hourly basis. This marginal cost is determined by computational algorithms that consider demand, supply, and system constraints. In this model, all electricity transactions, including those of the previous day and redispatches, are compensated at the price established in the previous day's market. As a result, the intersection of actual supply and demand does not influence pricing, either in the day-ahead or real-time market.

In markets such as Colombia, where the price is determined after dispatch, the price established on a specific day (t) for the following day's market (t+1) serves only as a reference and is not financially binding. Following this market, redispatches adjust supply and demand based on system events. These redispatches may not be efficient for integrating large amounts of renewable technologies, since the lack of price signals does not allow for the efficient allocation of the additional costs generated by redispatches and imbalances, nor for taking advantage of cheap resources available on the intraday horizon (Mastropietro *et al.*, 2020). Finally, an ideal uninodal dispatch is calculated after the actual dispatch, at (t +2), establishing the short-term prices and performing reconciliations. The ideal dispatch is the generation that uses the most economical resources to meet the total demand, considering the commercial availability and technical characteristics of the generators, without considering system constraints.

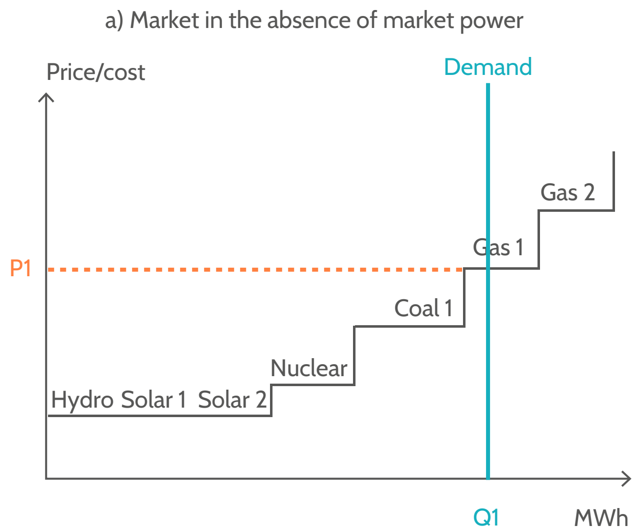
Granularity varies and so does the market horizon. The DAM generally has an hourly granularity and a one-day horizon, while the IDM usually has a narrower horizon and finer granularity. This space facilitates electricity trading after the end of DAM operations and shortly before real-time activity—typically a few hours prior to dispatch; the RTM operates very close to the actual time of electricity dispatch, which involves adjustment intervals that can range from five minutes to one hour.

3.1.3. Competition

Market power—the ability to raise prices above competitive levels—is a recurring concern for electricity market regulators. While there is no consensus on what type of dispatch and what level of market granularity foster greater competition among participants, competition in the market will be influenced by network vulnerabilities that can be exploited in any system (Eicke & Schittekatte, 2022). Market power can generally be exercised by physically withholding generation or by bidding at auctions for a price above marginal cost, mainly in bid-based markets (Pham, 2019). Panel A of Figure 5 shows how prices are determined in a competitive market. The Gas 1 plant sets spot electricity prices according to a specific demand. However, a scenario in which a single company owns Solar 1, Nuclear, and Gas 1 plants and exercises its market power by withholding Gas 1 generation results in the start-up of Gas 2, which has higher marginal costs. The price therefore increases from P1 to P2 (see Panel B) and could generate higher profits for the company.

Another strategy to exercise market power during auctions is to submit a bid with a price that exceeds the marginal cost, especially when demand is high, as demand shifts to the right of the merit order curve, reaching higher marginal costs. Although in situations of scarcity prices can reach very high levels, the exercise of market power is sometimes tolerated because these high prices are necessary to create incentives to encourage investments in energy-only markets.

FIGURE 5. Example of market power in electricity markets



Source: Prepared by the authors based on Pham (2019).
Note: In both cases, the sky blue line indicates demand. Participants' bids are listed according to plant technologies. In the first scenario, a competitive market, Panel A illustrates the equilibrium price based on a specific demand. In the second scenario, if we imagine that a market participant controls Solar 1, Nuclear, and Gas 1 plants and decides not to use Gas 1 capacity because it is the least profitable, then the Gas 2 plant would have to operate to meet demand. In this case, the marginal cost of Gas 2 will establish the market price. (P2). Although this participant does not use one of its plants, it obtains higher profits in this equilibrium with market power.

In a context with many producers and complete information, all market designs potentially result in the same efficient dispatch (Holmberg & Lazarczyk, 2015; Fabra, Von der Fehr & Harbord, 2006). Most of the literature indicates that if generators can act strategically, pay-as-bid tends to be more effective in curbing market power (Dechenaux & Kovenock, 2007; Fabra, 2003; Kahn, 2001). There is also evidence, however, that pay-as-bid auctions can increase the exercise of market power (Heim & Götz, 2021; Cramton & Stoft, 2007). Cost-based markets are not exempt from strategic behavior on the part of participants. Despite the fact that marginal costs are audited, market players can operate strategically, mainly in concentrated markets with barriers to entry. This could guide the market towards a long-term equilibrium with prices exceeding those of a competitive market, especially if investments are not regulated (Muñoz *et al.*, 2018).

An essential requirement for competitive and efficient markets is to ensure unrestricted access to the transmission network for all sellers and wholesale buyers.

Given the critical importance of the transmission sector in promoting effective wholesale competition, it is crucial to ensure the independence of transmission operations from other market players, such as generators, retailers, and distributors/traders (World Bank, 2013; Lee & Usman, 2019). Promoting robust independence between market operators and regulators is also essential to ensure efficient and transparent markets. Finally, it is also essential to establish effective monitoring of anticompetitive practices and to apply the appropriate sanctions.

The spatial granularity of markets determines the behaviors that participants adopt to influence market prices. Under the zonal pricing model, redispatch incentivizes the interplay between the wholesale market and the ancillary services market to resolve network constraints. In this context, additional payments to producers in export-restricted zones may result if they make a profit from the arbitrage of price differences between the zone market and the redispatch stage (Alaywan, Wu & Papalexopoulos, 2004; Graf *et al.*, 2021; Holmberg & Lazarczyk, 2015), a strategy known as the increase-decrease (inc-dec) game. Hirth & Schlecht (2020) emphasize that such a game is possible even without market power, but market power further increases the magnitude of the problem. Redispatch in bid-based markets generally tends to be more vulnerable to gaming strategies and the exercise of market power compared to cost-based redispatch.

Nodal pricing has the advantage of avoiding inc-dec play, since there is no inconsistency between the trading area and the physical area of the transmission network (Eicke & Schittekatte, 2022). Nevertheless, nodal pricing has also been the focus of criticism, given the presence of market power in wholesale markets (ENTSO-E, 2021; Antonopoulos *et al.*, 2020). The nodal configuration, by determining prices at each node, opens the door to the possibility of strategically located stakeholders in the network exerting an inordinate influence on electricity prices. In situations where the network is constrained, a high market concentration in a node or set of nodes may arise. This means that one or a few generators control a large portion of the generation capacity in a market area over a short period of time. Such a concentration may present opportunities for price manipulation.[17]

3.1.4. Contracts

The wholesale price of electricity can be determined by both short-term markets and medium- and long-term contract markets. Participants use medium- and long-term hedging contracts as a strategy to hedge against short-term market price volatility. These contracts also often serve as tools to ensure sufficient generation asset availability, to provide protection against price variability, and to meet the requirements of ancillary services needed in the electricity system. **Depending on the sophistication, size, and bargaining power of the end users, these contracts can be entered into through bilateral agreements or through auctions.** In the first case, the parties involved are free to design the contract according to their specific needs, establishing parameters such as duration and price indexation. These bilateral contracts may extend for considerable periods of time, even more than five years. Their main purpose is to provide predictability and guarantee a preset price for the agreed quantity to both buyer and seller, which allows both to protect themselves from market fluctuations. In the case of auctions, contracts are allocated through a competitive mechanism in which multiple participants submit bids, and prices result from the interaction between market supply and demand.

Power Purchase Agreements (PPAs) are contracts between energy consuming companies and energy generators that are made through auctions or bilateral agreements, where the company commits to purchase future energy from the generator at preset prices. PPAs are beneficial to generators, offering price certainty for their power generation, which is advantageous over short-term fluctuating market prices. While PPAs guarantee predictable revenues for generators, they can “freeze” prices in technologies such as solar and wind, whose costs are steadily declining. This can result in purchasing companies paying above-market prices. Furthermore, variability in the output of renewable energy generators can present technical and financial challenges for both purchasing companies and generators, depending on who assumes the risk in the contracts.

In some cases, the generator assumes the risk of market volatility and guarantees the delivery of energy at the agreed price, thus protecting the buyer. In this type of contract, if the generator cannot produce the committed energy, it must purchase it in the short-term market to meet its obligations, assuming the risk associated with variability in generation and prices.

[17] Mechanisms to counteract market power have been established in nodal markets in the United States. Potential abuses are automatically assessed prior to settlement and bids from generators in strategic locations and with potential for influence are limited (Anselm & Schittekatte, 2022).

The most common types of financial risk hedging contracts are call option contracts and contracts for differences (CFD).

In call option contracts, the buyer has the right, but not the obligation, to purchase a certain amount of electric power at a preset price (strike price) within a given period. In the standard call option model, in order for the buyer to have this right, it is assigned an economic premium per MW contracted, a sunk cost for the buyer that should not influence subsequent decisions. The first openings in Latin America to private investment occurred through competitive processes that resulted in a call option type contract, with payments for available capacity and payments for energy dispatched. Fuel risk—for example, natural gas—was borne by the buyer, so that the generator could be considered as an energy assembler, with a thermal regime established by contract.

In a call option contract, the buyer sets a ceiling on the price of energy. If the price of electricity in the underlying market (DAM/RTM) is higher than the strike price, the holder executes the call option. On the other hand, if the price of electricity is lower than the strike price, the holder is not obligated to exercise the call option, since it is cheaper to purchase the energy directly on the market.

In CFDs, payments are established for the difference between the market price (LMP in the DAM/RTM) and the contractual price for the contracted quantity. If the difference is positive, the seller pays the buyer, and if it is negative, the buyer pays the seller. The contract price may be determined by auctions or by the regulator. The contracted amounts can be fixed (in the case of purely financial contracts), or for a percentage of the energy actually generated, which is usual for intermittent generators, with periodic balances (month/year).

Long-term and short-term electricity markets complement each other significantly, providing a balance in the electricity markets. For example, in bilateral contracts, the companies involved in these contracts often resort to the short-term market to adjust their positions according to their actual needs. For instance, if a company underestimates its energy demand in a bilateral contract, it needs to buy additional electricity in the short-term market to cover the shortfall. On the other hand, if it overestimates its demand, it may choose to sell the surplus in this market. These adjustments become more relevant with the generation variability of renewable energy generators. Additionally, when prices in the bilateral contract differ from spot market prices, companies can use CFDs. These CFDs allow the differences between the price agreed in the contract and the market price to be adjusted, thus providing a flexible mechanism to align contractual commitments with market conditions. An additional relationship is that some long-term submarkets use spot market prices as a reference, as these prices represent the final cost of electricity under current supply and demand conditions. Consequently, derivatives markets, including forward contracts and options, are largely influenced by projections and expectations about how these markets will evolve in the near term in the future.

3.1.5. Maximum prices

Short-term markets were implemented through reforms to electricity systems around the world, and a consensus was reached on the importance of these markets sending the right signals to inform and encourage investments, minimizing interventions that could distort these signals. Many short-term wholesale electricity markets currently have limits on bid prices, or on the magnitude of the market equilibrium price.[18] The reasons are varied, including limiting the market power of participants and avoiding extreme increases in electricity tariffs. These caps, however, also reduce the revenues that generating companies can receive during shortage conditions(Wolak, 2021; Schmalensee, 2019), known as the "missing money problem" for generation plants. Price caps can generate distortions that affect long-term market liquidity. In periods of high demand, the absence of market price signals to balance supply and demand tends to result in rolling blackouts, affecting all market participants and creating little incentive to participate in the markets in the long term.[19]

[18] The U.S. Federal Energy Regulatory Commission has imposed limits on bid prices in the wholesale energy markets (FERC, 2016). These limits are established in such a way as to allow companies to recover costs.

[19] This problem generates an externality known as the missing market. The externality arises when retailers or large consumers fail to internalize the cost of outages and prefer not to purchase energy in the future. For example, imagine a scenario in which one retailer purchases the necessary supply in the futures market to meet its demand while a second retailer does not. Paradoxically, both retailers face a comparable probability of suffering reductions in their supplies, thus blurring the incentives for contracting their energy needs in the futures market.

Regulatory interventions, aimed at modifying undesirable market outcomes, should only be considered as emergency measures. It is essential to avoid actions that significantly distort market dynamics, such as implementing price caps that are too low. Price caps, for example, should be high enough to stimulate investment (Wolak, 2003).

Unjustified regulatory interventions may discourage investors. There must be a balance between managing the risks associated with excessive market power and restrictive regulations that could harm the functioning of the market. Interventions, and even market suspensions, could be justified in cases where, for example, generation capacity is withheld and there are risks to the reliability of electricity supply. Such intervention should follow a rational and predictable process, ideally specified in concrete rules and procedures. There is always, however, a danger that provisions for market intervention will be used for political purposes, such as when seeking to reduce electricity price volatility at election campaign time if they are perceived to be too high to be passed on to households. It is essential that market adaptations, driven by public policy objectives, serve to harness the benefits of competition and establish investment incentives as the most efficient means to achieve the desired outcomes (Foster & Rana, 2020).

In the case of markets based on audited costs, since the regulator verifies generation costs, in a way it imposes limits on them, which can be considered a form of market intervention. **While these limits could reduce the capacity for market power, they also substantially reduce the income that companies could earn under scarcity conditions.**

3.2 Factors associated with the electrical infrastructure

Intrinsic physical limits determine the maximum power capacity that transmission systems can carry, which has a direct impact on short-term price structuring. Possible constraints include network congestion, inherent electrical losses, and operational constraints due to reliability. Expanding interregional transmission capacity can enhance grid reliability, promote the integration of new generation resources, and thereby reduce electricity prices in the short term. In turn, the inherent intermittency of renewable sources such as solar and wind represents a paradigm shift in the pricing dynamics of the electricity sector. Given the non-constant nature of these sources, they must be supplemented with other forms of generation during their non-production or storage periods. This leads to a remarkable variability in prices: close to zero when these sources can meet demand and above zero when it is another technology—usually thermal plants—that sets the market price. The following subsection explains how these factors influence price determination in wholesale electricity markets.

3.2.1. Availability of generation plants, congestion, and electricity losses

The availability of power generation plants plays a crucial role in shaping the electricity supply curve, especially during peak demand. The unavailability of power plants may be due to technical factors, such as scheduled shutdowns (maintenance) and unscheduled shutdowns (electrical failures and problems), or to non-technical factors, such as shortages of production inputs (fossil fuels or water), political factors, and environmental regulations, including coal plant retirement policies.

It should be noted that scheduled shutdowns, such as maintenance, are planned ahead and communicated to the system operator. When power plants with lower marginal costs are unavailable due to these factors, the short-term price is usually higher, as plants with higher costs must be dispatched to meet demand. In extreme peak demand situations, power plant unavailability and the absence of price incentives to reduce demand can lead to blackouts due to insufficient generation. Likewise, unscheduled outages may require the dispatch of plants that tend to have higher marginal costs to meet demand.

Among the non-technical factors influencing power plant operations, regulations play a significant role. For example, in the case of hydroelectric power plants, water use may be dictated by other priorities, such as agricultural irrigation. This implies that the plant can generate electricity when water is needed for irrigation, not necessarily when it is required to meet electricity demand, thus altering the structure of the dispatch order and potentially increasing system costs by having to resort to other, more expensive, generation sources

Transmission line congestion is one of the power system conditions that affect electricity prices.

Since energy is expensive to store, transmission line congestion can cause energy prices to rise dramatically over time and depending on location Transmission line congestion occurs when the power flow on a line reaches its operational limit, requiring the use of local, often more expensive, power plants to meet demand. In essence, congestion is the cost of being unable to meet demand from less expensive exporting regions (Hadsell, 2006; Hadsell, 2009). In addition, when electric power goes from the generating plants to the transformers, it encounters resistance in the transmission lines. This resistance, inherent to conductive materials, causes part of the energy to be dissipated in the form of heat, which is known as electrical losses in the transmission of electricity.

A market based on nodal prices typically reflects congestion and electricity losses in each price. Zonal prices ignore these costs, but they are included in the redispatch costs. Since nodal prices incorporate fluctuations in factors such as losses and congestion, they are inherently more volatile than zonal prices.[20] The intention is to provide accurate economic signals to market participants and enable them to adjust their operational and strategic decisions based on actual network conditions. The aim is to encourage producers, consumers, and storage firms to choose strategic locations aligned with market conditions and the particularities of the transmission network (Eicke & Schittekatte, 2022; Antonopoulos *et al.*, 2020).

Hadsell (2009) has mentioned two potential remedies for congestion: adding transmission capacity and adding generation capacity near high demand areas. Both solutions present challenges. The main problems with the first solution are cost recovery and opposition from exporting regions. As for adding generation capacity in high demand areas, this is no easy task, as it faces political, social, and environmental constraints.

One way to mitigate nodal price volatility due to congestion is to acquire Financial Transmission Rights (FTRs), also known as transmission congestion contracts. This financial instrument provides protection against congestion between two regions.

FTRs competitively allocate limited transmission line capacity, allowing incumbents to receive compensation or pay charges based on price differences between origin and destination nodes. It should be noted, however, that FTRs do not solve congestion per se; line capacity still has a physical limit. FTRs simply provide a mechanism to manage the financial risk associated with congestion and efficiently allocate available capacity.

[20] By not integrating these restrictions, zonal prices tend to be more stable.

3.2.2. Electricity market integration

The integration of electricity markets—bilaterally, multilaterally, or with a unified market—offers several benefits, including the possibility of leveraging economies of scale, enabling the development of large generation projects, and facilitating access to cheaper sources of electricity generation resources. Increasing the number of generators in the system helps manage peak demand by sharing reserves among markets. Moreover, increased competition favors plants with lower marginal costs and displaces those with higher costs. Integration in energy trading can take various forms, depending on the number of jurisdictions involved and how responsibilities are structured and coordinated within the system.

The main modalities of integration are described below:

- **Bilateral integration:** energy exchanges occur between two jurisdictions and coordination and management are carried out directly between the parties, without involving additional agencies.
- **Multilateral integration:** three or more jurisdictions can trade energy with each other. Underlying market structures within jurisdictions can vary considerably, but coordination is achieved by developing regional institutions, which act as facilitators and help manage trade without replacing existing local institutions.
- **Unified integration models:** regional institutions assume a more prominent role and take on all or some of the energy system management responsibilities across multiple jurisdictions, which may include market organization and, in some cases, system operations.

In the multilateral integrations model, the coordination of surplus generation trade is crucial for the stability and efficient operation of the system. Should a certain market experience excess generation at a certain point in time, this excess can be traded with other markets that may have additional demand. This commercialization process should be coordinated by specialized regional institutions, with specific mandates to collect detailed information on surplus supply and demand in the different jurisdictions, match potential exchanges and oversee the collection and distribution of the corresponding revenues. These institutions do not replace local institutions.

Integrations can also be complete or partial. A complete integration of the electricity market is achieved when the markets are entirely consolidated into a single electricity dispatch. This contrasts with partial integrations, which may include long-term components, such as system planning and power purchase agreements, and short-term ones, such as ancillary services and real-time dispatch. Complete integration means closer coordination and alignment of operations at all these levels and allows for greater efficiency and flexibility in the power system as a whole (IEA, 2019).

Bilateral forms of integration predominate in the region, representing the first step towards eventual market integration. These types of integration are detailed in Table 2. The Regional Electricity Market (REM) has been developed and the infrastructure of the Electrical Interconnection System of Central American Countries (EISCAC) has been built in this context. The main bodies of the REM are the Regional Electricity Interconnection Commission (REIC), which is the regulatory body; the Regional Operating Entity (ROE), and the REM Steering Council (REMSC), which is the body in charge of monitoring and guiding policy implementation in the region.

Regional electricity integration has important benefits, which may favor the consolidation of more competitive prices.

TABLE 2. Examples of electricity market integration

Type of integration	Market
Bilateral	Colombia-Ecuador Ecuador-Peru Chile-Argentina Argentina-Paraguay Brazil-Paraguay Argentina-Uruguay Uruguay-Brazil United States-Mexico
Regional	SIEPAC (Costa Rica, El Salvador, Guatemala, Honduras, Nicaragua, and Panama)
Unified market structure, differentiated operations	Nord Pool (Nordic and Baltic countries)
Unified market and operations	PJM (United States) Australian National Electricity Market

Source: Prepared by the authors from the IEA (2019).
Note: In complete market integration, such as the PJM in the United States, both market and system operations are contained in a single institution. Nord Pool, on the other hand, is a regional energy market that operates in several countries, each of which maintains full control over system operations.

According to IEA (2019) & Levy, Tejeda & Di Chiara (2020), these benefits include the following:

- **Improved economic efficiency:** integration strengthens the demand management of the markets involved and promotes a more efficient use of generation technologies and transmission infrastructure between countries. This reduces the need for reserves and may allow countries to postpone or avoid additional investments in generation.

- **Demand curve combination:** Integration allows demand curves from different countries or regions to be added together and combined. This may result in a more balanced aggregate demand, with less pronounced peaks or peaks distributed at different times.

- **Renewable resource offsetting:** In large, interconnected regions, electricity integration allows taking advantage of the complementarity of different renewable energy resources. Water (hydrology) and wind (wind regimes) resource availability variations in different areas can offset each other.

- **Greater integration of renewable energies:** greater integration can also increase renewable energy penetration and, given the low marginal costs of these technologies, lead to lower prices.

- **Leveraging economies of scale:** regional integration facilitates the implementation of large-scale generation, transmission, and international interconnection projects. This can lead to greater efficiency and lower costs in energy production and delivery.

- **Creation of competitive markets:** integration promotes competition in the energy market. A larger market allows for greater liquidity in these products, increases competition, and minimizes the risk of oligopolistic behavior.

- **Macroeconomic impact mitigation:** electricity integration mitigates the economic repercussions derived from fuel price fluctuations in global markets. This mitigation is manifested in the balance of payments, particularly in relation to generation inputs, such as imported fuels, and in the consumer price index.

In the context of interregional integration, there are particularities that can intensify energy price volatility.

Based on studies such as those by Oseni (2016) and Zareipour (2007), we can highlight some disadvantages to be considered in the integration of electricity markets:

- **Import transaction failures:** Import transaction failures force the market operator to instruct the dispatch from power plants with high production costs, which can cause unusual price spikes and increase price volatility.
- **Export transaction failures:** Export transaction failures force the market operator not to dispatch energy from some of the marginal power plants, which may cause unusually low prices and increase energy price volatility.
- **Imported volatility:** regions with higher internal energy price volatility will be able to export their volatility to other regions. This volatility can be mitigated by entering into long-term contracts.

3.2.3. Growth of variable renewable energies

Variable renewable energy is expected to hold a prominent position in the global electricity supply market in the coming years. This phenomenon stems from the aggressive decarbonization targets and plans adopted in many countries' electricity markets, and is facilitated by the sustained decrease in the costs associated with renewable technologies and their increased efficiency, which makes them increasingly competitive with fossil fuel-fired thermal plants (IRENA, 2023). The expansion of the renewable energy supply has been particularly notable due to the penetration of solar and wind energy sources (IEA, 2023). This is a profound transformation of markets previously dominated by conventional energy.

Increased penetration of VREs has the potential to change short-term electricity market pricing patterns and deviate significantly from traditional patterns (Seel, Mills & Wiser, 2018). The marginal cost of renewable energies, often close to zero due to their low operating costs, is different from that of thermal plants, which traditionally set the marginal price and represented the cost of adding an extra unit of energy. This new dynamic may influence the price signals that incentivize future investments, as low marginal prices may not adequately reflect the need for new generation capacity or back-up infrastructure to ensure the reliability of the electricity system. The specific consequences of this impact will vary depending on the particularities of each market, and factors such as demand patterns, the quality and nature of the VRE, the composition of the electricity matrix, and existing backup plants will play determining roles in the configuration of wholesale prices (Felder, 2011; Wiser *et al.*, 2017).

In general terms, the impacts of a greater implementation of renewable sources on prices are as follows, according to Seel, Mills & Wiser (2018):

- **Lower prices will be observed during periods of high VRE generation and higher prices when VRE generation is low.**
- **Price volatility and unpredictability are likely to increase,** reflecting the variable—weather-dependent—nature of VRE generation.
- **Geographic patterns of wholesale electricity prices will change,** resulting in lower prices in regions with concentrated VRE deployment.
- **In a context of low (or even negative) marginal costs, wholesale electricity market prices will tend to be lower,** especially before a capacity balance is achieved. This will help to remove plants with higher costs more quickly.
- **In terms of capacity balance,** there will be a trend towards higher revenues from ancillary services markets and capacity markets (where they exist), or from scarcity events;[21] on the other hand, less revenue may be derived from the short-term energy market.

[21] Revenues in scarcity events refer to the idea of raising energy prices above the marginal cost of the operating generating unit when the system lacks generation capacity. These scarcity prices result in profits for the generating plants that contribute to covering the capital costs of these units.

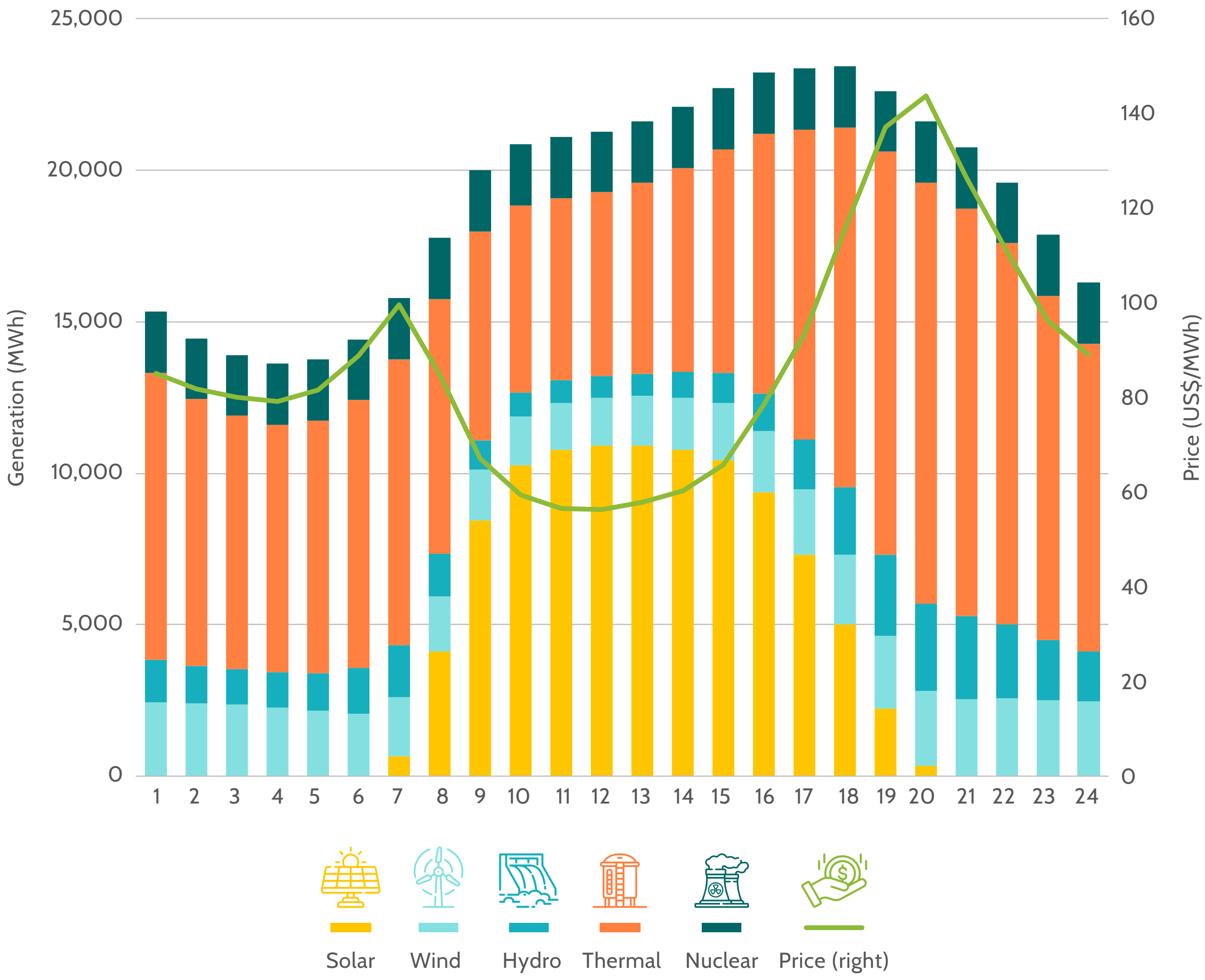
In general, the effects of the integration of renewable energies in the electricity market manifest through a decrease in short-term electricity prices and an increase in their volatility. In the short term, the increased share of renewables may reduce spot market prices, which can be attributed to the merit order dispatch effect (Browne, 2015). As for price volatility, this is mainly due to possible fluctuations in generation (Blazquez, 2018; Baule, 2019; Kettener, 2014; Gilmore *et al.*, 2015; Wiser *et al.*, 2017).

The California Independent System Operator (CAISO) area, one of the regions with the highest integration of renewable sources in the United States, provides a telling example of the above. In 2022, approximately 21% of this region's electricity was generated by solar plants. Figure 6 shows the relationship between solar plant operation and electricity prices in this market.[22] There is a trend whereby electricity prices tend to decrease during periods when solar plants are in operation. Conversely, when—in line with their daily cycle—they cease operations, prices tend to rise. This phenomenon, while contributing to lower prices through solar plant operation, also introduces price volatility at the intraday level.

Integration could be more effective if it were accompanied by an increase in the dispatch capacity of lower-cost sources, such as hydroelectric, geothermal, or storage. These sources can serve as buffers to manage and mitigate the volatility inherent to VRE sources. Increasing storage capacity and improving demand management are key strategies to facilitate a more orderly transition to a higher share of renewable energy (IEA, 2023). In contrast, relying solely on thermal plants for backup can perpetuate price volatility due to the nature of the dispatch order system in the electricity markets.

[22] The CAISO market is presented as a relevant case study due to the outstanding integration of renewable energies in its energy matrix. This high incorporation provides a clear perspective on the potential effects and challenges of such a transition to cleaner energy sources.

FIGURE 6. **Electricity generation and hourly price of electricity in the California market (CAISO), 2022**



Source: Prepared by the authors.
Note: The green line shows the 2022 annual average of the CAISO system's hourly day-ahead price. This was estimated as the hourly average of the local marginal price. The bars show the average generation per hour according to technology in the CAISO system. Average marginal electricity prices are observed to decrease as solar generation increases.

3.3 Exogenous factors

The exogenous factors affecting prices in the electricity markets include short-term demand, fuel prices (in the case of thermoelectric plants), and environmental conditions (in the case of renewable energy plants). Short-term energy demand will determine the generation plants required for the market to operate. The prices of fuels such as coal, natural gas, and oil—largely affected by global market dynamics and government policies—determine the marginal costs of thermal power plants (Tamayo, 2016). Environmental conditions, such as sun intensity, wind speed, and water availability, directly affect the efficiency and production capacity of renewable energy plants, and may result in unforeseen energy supply fluctuations and price volatility.

3.3.1. Short-term demand and capacity

Short-term demand is highly inelastic and is generally decoupled from the supply of electricity, since most consumers pay a fixed price for electricity, which is determined on a monthly or bimonthly basis. Nevertheless, demand plays a central role in determining prices. In a merit order dispatch model, power plants are arranged from the lowest to the highest production cost and those needed to meet the actual system demand are dispatched. Although in this market structure the marginal plant is the one that determines prices, such determination will be directly influenced by the demand for electricity.

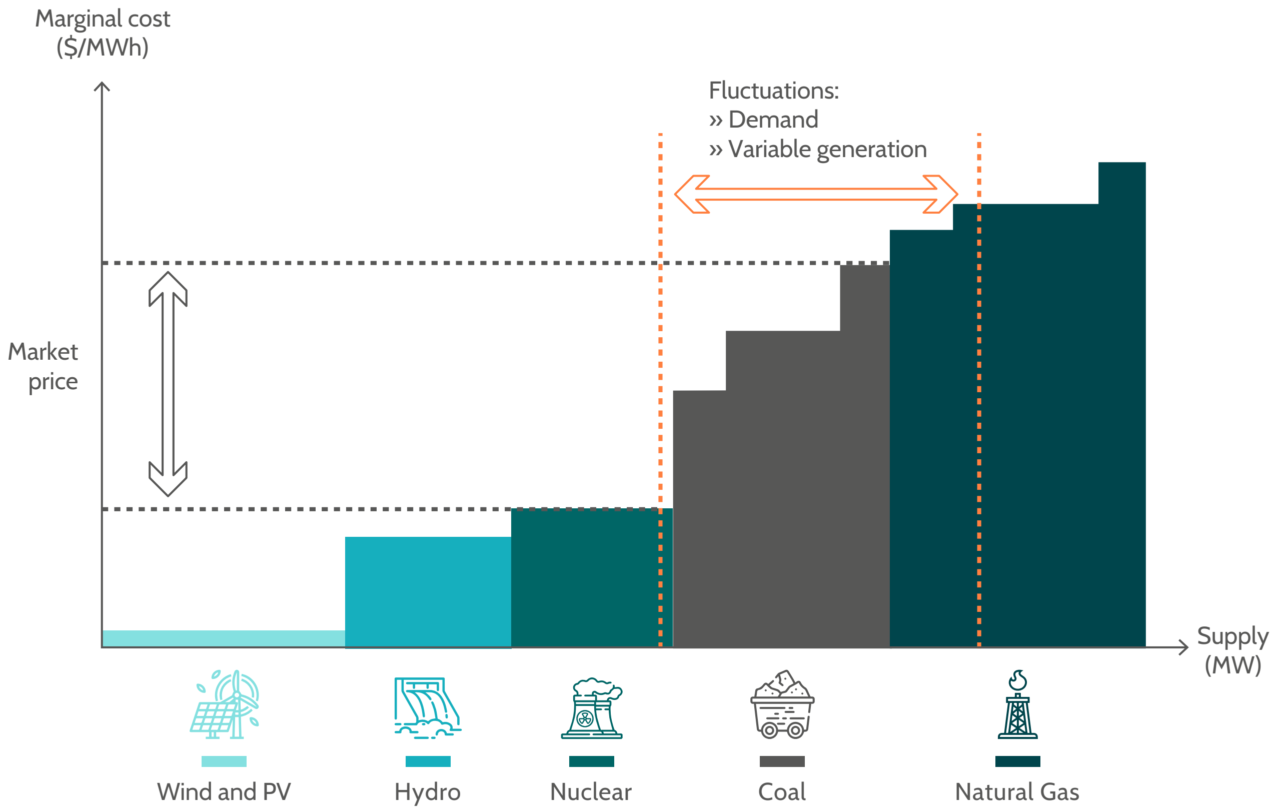
In a traditional electricity market that mainly uses dispatchable thermal and/or hydroelectric plants as the base energy source, price dynamics are characterized by three distinct periods: low demand, medium demand, and high demand.

- **During periods of low demand,** the base plants are the ones that inject energy into the systems. Thus, the cost of generation is closely linked to the system's base technologies. For example, in countries where hydropower has a significant presence in the energy matrix, the cost is mainly associated with the cost of hydroelectric power plants.
- **During periods of medium demand,** in addition to the base plants, it is essential to activate the intermediate marginal cost plants to cover energy needs. In this scenario, the price is aligned with the operating cost of the latter.
- **During periods of peak demand,** the price is set in such a way that a balance between supply and demand is sought to ensure that demand does not exceed total generation capacity. This could lead to a combined cost that would exceed that of all technologies. In this context, what is known as "scarcity rent" arises; the plants with the highest marginal costs are the ones that operate and, therefore, determine the market price (Pollitt *et al.*, 2022). It is economically efficient, since the low-cost base plant operates all the time, while the more expensive peak-demand technology only operates when necessary. This dynamic has changed, however, in markets where variable renewable energy (VRE) sources can meet peak demand, preventing more expensive plants from being activated during these periods.

High energy storage costs have traditionally forced a permanent balance between generation and demand, resulting in high price volatility. A minor change in short-term demand can affect power plant dispatching in a system and cause prices to rise or fall for short or long periods before returning to their normal condition, an effect known as mean reversion (Hélyette, 2006). Battery prices, however, have decreased substantially in recent years and could become competitive and scalable in the near future. This would open up the possibility of storing energy and, therefore, reduce price volatility in the electricity market. In this context, the electricity matrix, forced generation outputs, and system conditions play a crucial role in the dynamics between supply and demand, determining which technologies are the generation base and which plants satisfy the peaks that determine short-term energy price levels, as shown in Figure 7. These factors affect price determination regardless of market design.

Price spikes can occur when demand is inelastic, which will cause supply to be met by using peaker generation plants. This, in addition to grid congestion, can drive up the price of energy (Asadinejad, 2017).

FIGURE 7. Energy price volatility due to demand and generation fluctuations



Source: Prepared by the authors.
Note: The orange line indicates demand. The bids of the different participants by technology are marked by colors. Accepted bids are those that satisfy the demand.

3.3.2. Fuel prices

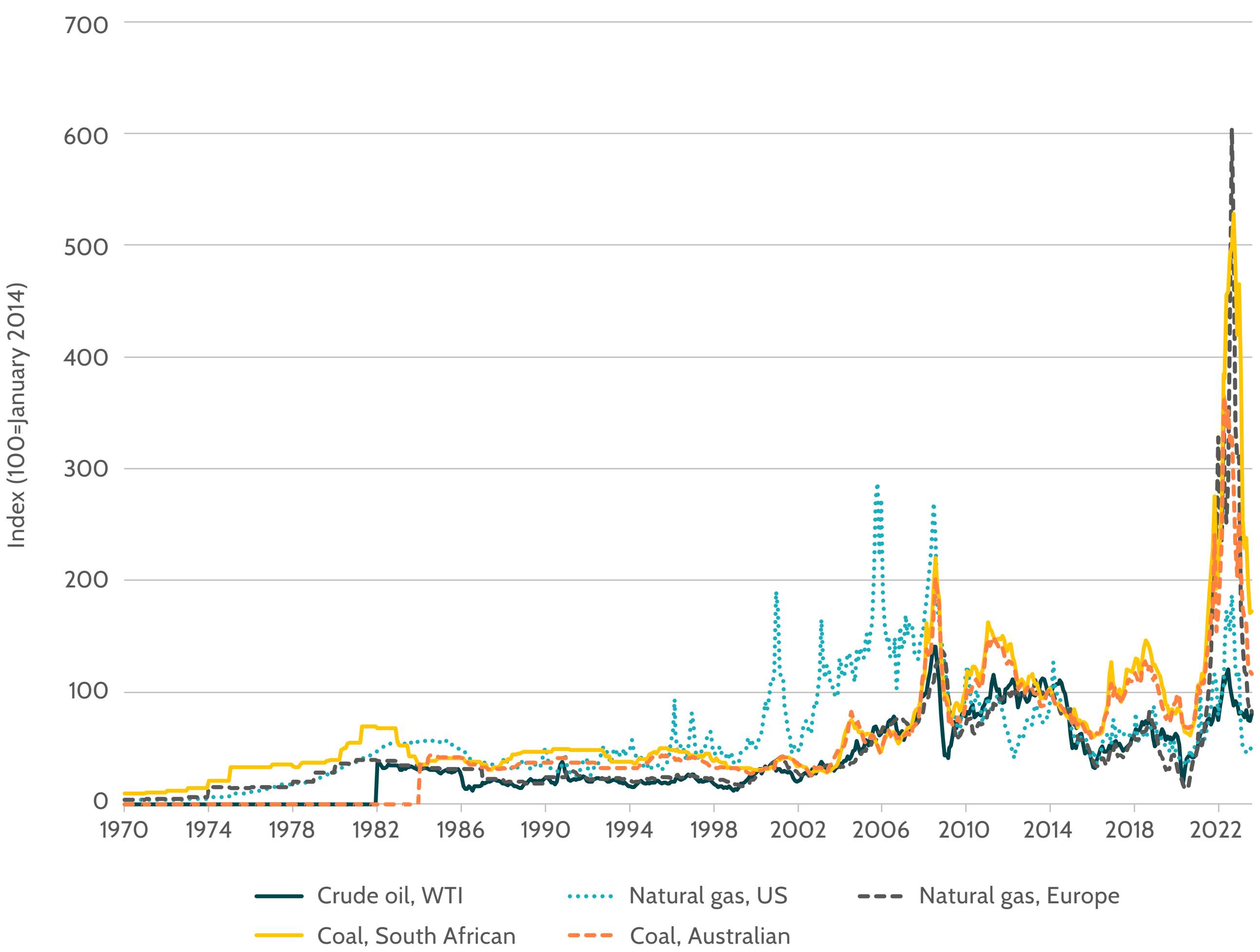
In markets with a high presence of conventional generators, energy prices depend on fuel costs, as these plants are normally the marginal generators in the market. In other words, the spot price of energy is highly correlated to the price of fuels used to generate energy. Although fossil fuel prices show similar patterns in the long term, they are highly volatile in the short term (Mohammadi, 2009; Oberndorfer, 2009). The pass-through effect of fuel prices to electricity will depend largely on the degree of hedging by market participants using these inputs. The world has undergone multiple energy commodity price shocks over the past fifty years, as shown in Figure 8 (Hamilton, 2009; World Bank, 2022).

These shocks have had a significant impact on electricity markets, and specifically on prices.

It was in response to the high prices that policies aimed at the development or substitution of certain energy sources within the electricity matrix were implemented. For example, following the price shocks of the 1970s, oil consumption fell in advanced economies, mainly due to a ban on the construction of oil-fired power plants, which were replaced by nuclear and coal-fired power plants (Scott, 1995; World Bank, 2022). During the 2000s, high oil prices and certain changes in government policies once again led to improvements in the efficiency of oil use, while there was less substitution of oil for other sources, as the amount of this input used in electricity generation was much lower. The 2022 energy crisis in Europe, caused by the disruption of natural gas supply and the high dependence on this fuel, triggered a sharp increase in gas prices. Faced with this situation, many European countries have decided to accelerate their transition plans towards renewable energy sources, such as solar and wind energy. This strategic decision is based on the greater energy security offered by renewable sources, as they are not exposed to interruptions due to geopolitical conflicts.

In the current context, understanding price volatility in energy commodity markets, illustrated in Figure 8, is crucial to understanding the dynamics of global electricity markets. The phenomenon has become increasingly prominent in recent decades, with shocks that have led to high-impact price increases and caused disruptions not only in electricity markets, but in the economy as a whole. For example, a study by Gelos & Ustyugova (2017) covering a set of developed and emerging countries between 2000 and 2010 shows that those with a more intensive use of fossil fuels are more exposed to sustained inflationary effects from commodity price shocks.

FIGURE 8. **Main fuel prices, 1970-2023**



Source: Prepared by the authors with commodity markets data from the World Bank.
Note: The figure shows a base index (January 2014) for the prices of the main energy commodities in the world. The prices of the main fossil fuels are highly volatile. This volatility is usually reflected in the electricity markets in most cases.

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3.3.3. Climate factors

Renewable power plants use natural inputs such as water, wind, and sun, which makes them vulnerable to changes in climate.

Climate fluctuations can significantly alter these plants' generation capacity (see Table 3). For example, in hydroelectric power plants, a prolonged period of drought can reduce the availability of water resources and drastically reduce generation capacity. Similarly, solar and wind power plants are subject to the respective variations in solar radiation and wind speed. When renewable energy generation capacity decreases, it is usually replaced with generation from thermal plants, which tend to have higher marginal costs. This may lead to higher energy prices. In addition, in markets with a significant reliance on hydroelectric generation, reservoir management can create additional price volatility. As noted by Tamayo (2016), the level, inflows, and use of reservoirs determine the opportunity cost of water, which can influence price formation methods in these markets.

TABLE 3. Examples of climate change impacts on power generation plants

Type of plant	Types of impact
Hydroelectric	» Change in generation potential due to fluctuations in precipitation patterns. » Decrease in generation potential due to increased reservoir evaporation losses.
Solar	» Changes in atmospheric water vapor content, cloudiness, and cloud characteristics, all of which affect solar potential. » Reduced efficiency of solar PV modules and thermal power plants due to heat waves and forest fires.
Wind	» Changes in geographic distribution and wind speed, which affects generation potential. » Increased incidence of storms that force production to be limited.
Thermal	» Lower efficiency of water-cooled thermal power plant technologies due to increased cooling water temperature. » Partial reduction of production or total shutdown of thermal power plants due to insufficient availability of cooling water. » Limits to river transport of coal in case of drought.

Source: Prepared by the authors based on IEA (2021).

In South America, the El Niño[23] phenomenon tends to affect normal market development due to changes in rainfall, temperature, wind patterns, and solar radiation. In northern South America, Colombia, Venezuela, and northern Brazil are affected by a rainfall deficit, which causes droughts, increased temperatures (and the resulting energy demand), reduced water resources for generation, and increased energy price volatility. On the other hand, in the south of the region, in countries such as Argentina, Bolivia, Paraguay, Peru, and Uruguay, and also in the south of Brazil, the El Niño phenomenon causes heavy rains that can bring floods and disable generation plants, increase electricity demand, and affect transmission/distribution networks (Tamayo, 2016).

These factors highlight the need for careful planning and management of renewable energy integration. A thorough understanding of weather patterns, diversification in energy sources, and the design of electricity markets that can adapt to these natural fluctuations are required.

[23] An event that occurs every two to seven years, related to the temperature of the surface waters of the tropical Pacific Ocean. The warm phase is known as El Niño, and the cold phase as La Niña.


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VOLATILITY IN EUROPE AND REFORMS TO WHOLESALE MARKETS

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VOLATILITY IN EUROPE AND REFORMS TO WHOLESALE MARKETS

During 2021 and 2022, short-term electricity prices worldwide reached levels that far exceeded initial forecasts.

This price surge prompted various governments to implement emergency measures to mitigate the impact on consumer electricity bills. In response to this situation, critical voices emerged, arguing that these temporary solutions were insufficient and advocated deeper reforms of the electricity markets instead. A clear example of these discussions took place in the European Union (EU), where the issue gained particular significance and sparked widespread debate.

Although Latin America and the Caribbean were not wholly immune to this price shock, the impact was relatively minor in the region, thanks to the significant presence of renewables in their energy matrix and the fact that trading occurs mainly in long-term markets. Additionally, unlike Europe, where natural gas prices fluctuated notably, in Latin America and the Caribbean—and in other regions of the world—these increases remained at relatively moderate levels. Market design differences also played a role. In the major markets of the European Union, the electricity market is characterized by a structure where short-term markets have greater relevance compared to Latin America and the Caribbean. The European model is based on a decentralized bidding system, zonal pricing, and multiple settlement markets.

The recent European crisis offers crucial lessons on the evolution of wholesale markets, lessons that could benefit the Latin America and Caribbean region in creating markets that achieve a higher degree of operational efficiency and resilience to such events. The following section presents the main stylized facts of the energy crisis in Europe and the energy policy recommendations that emerged from it.

4.1 The Role of Natural Gas

The increase in fossil fuel prices has profoundly impacted the volatility of global electricity markets, particularly in Europe. Factors behind these fluctuations include the global demand recovery following the COVID-19 pandemic crisis and trade disruptions due to Russia's invasion of Ukraine (World Bank, 2022). The reduced availability of hydro resources and nuclear power plants exacerbated the price impact. This impact was heterogeneous, depending on each country's different electric matrices, market design, regulations, interconnections with neighboring countries, and implemented policies (Ari *et al.*, 2022; Eicke and Schittekatte, 2022).

As mentioned in the previous chapter, there is a close relationship between the prices of fossil fuels such as natural gas and electricity prices, since the plants operating with this input are generally the marginal ones. This relationship is greater in countries with electric matrices more dependent on fossil fuels, such as Germany, Spain, Italy, the Netherlands, and Portugal.

> In the EU, gas-powered generators are decisive in setting short-term electricity prices.

This pivotal role of natural gas has been intensified since 2015 by several factors, such as the reduction in the price of this fuel prior to the pandemic and the increase in prices under the EU emissions trading scheme, which has favored gas over coal (Zakeri *et al.*, 2022). It is also due to their flexibility and lower carbon emissions that gas plants have become a central player in price setting in European markets, while the relevance of coal in the structure of electricity prices in Europe has been decreasing.

Ari *et al.* (2022) note that approximately 90% of the increase in wholesale electricity prices in Europe was attributable to increases in the cost of natural gas. Figure 9 illustrates the relationship between the volatility experienced in certain European electricity markets and natural gas prices. This is primarily because, in the European market, bids from thermal plants set the market price, especially when demand is high. The impact on wholesale electricity prices resulting from the increase in gas was exacerbated by a heat wave in Europe and the low availability of nuclear, hydro, and wind plants (Fabra, 2023).

The unique characteristics of each country's electricity matrix can influence their vulnerability to fluctuations in global energy commodity prices. During the period 2019-2022, natural gas contributed 16% to the electricity generation matrix in Germany; coal, 28%. In contrast, in Norway, gas generation was just 1%; the remaining energy was renewable, according to Ember data (2023). This disparity is evident in Panel A of Figure 9, where prices in Germany were consistently higher than in Norway. Both markets were affected by changes in gas prices but to varying degrees. In the case of Norway, the main factors were the importation of volatility from the integrated European market to which it belongs, low levels of hydroelectric reserves, and possibly the exercise of market power by some participants in the wholesale market (Zhu *et al.*, 2024).

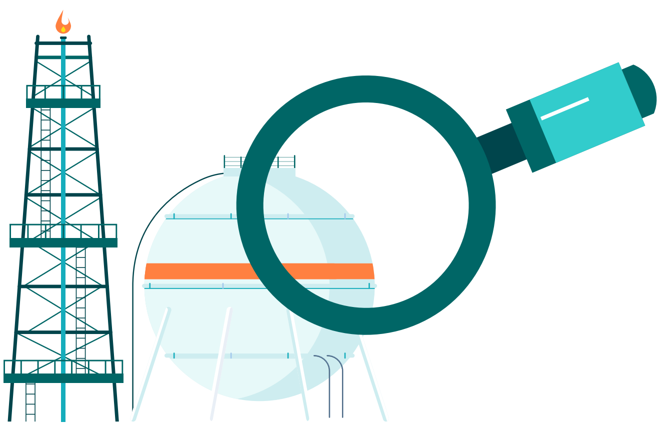
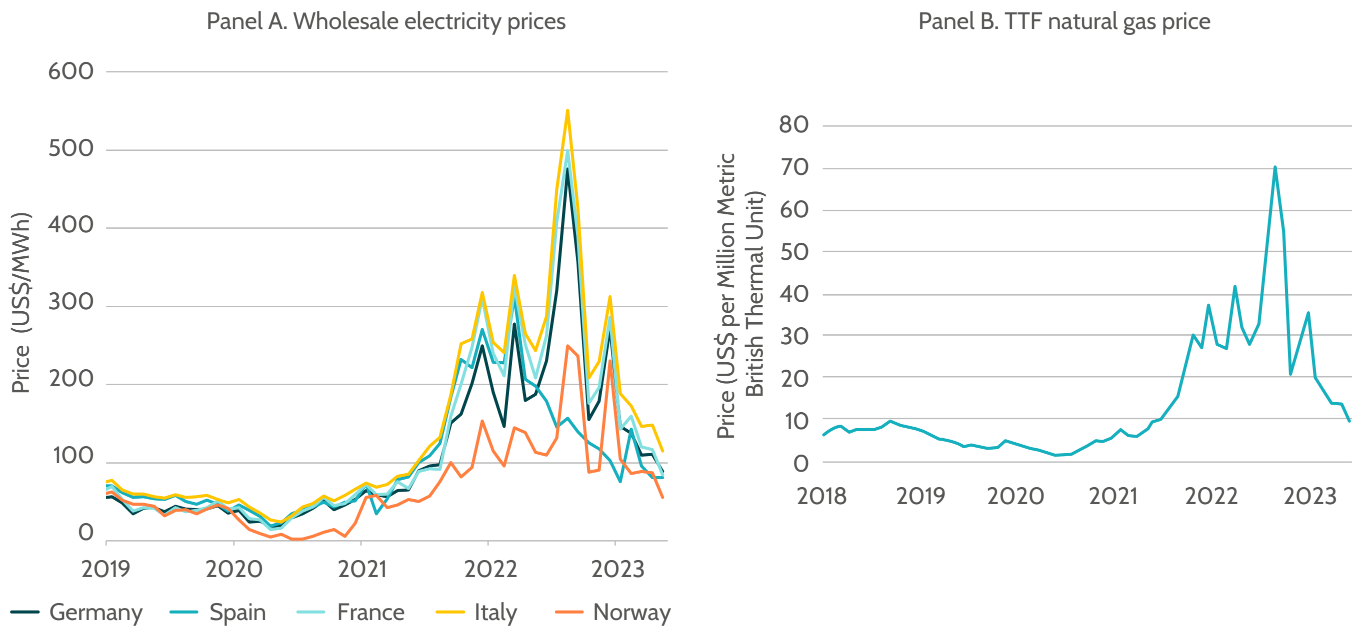


FIGURE 9. **Electricity and natural gas prices in Europe, 2018-2023**



Source: own elaboration based on data from ENTSO-e, EMBER, and Nasdaq.
Note: Panel A shows the day-ahead wholesale electricity prices for selected European countries. Panel B shows the prices of natural gas (Netherlands TTF Natural Gas Forward Day). It is observed that at the end of 2021, wholesale electricity prices increased substantially, and some days reached €700 per MWh. The trend in electricity prices coincides with that of natural gas prices, as natural gas is commonly used by the marginal plant, thereby setting market prices.

4.2 Measures in response to electricity price increases

In response to the drastic increases in wholesale electricity prices during 2021 and 2022, European governments implemented consumer protection measures, including subsidies, setting maximum prices in wholesale markets, and regulating the profits of generators.[24]

The estimated cost of these interventions reached €651 billion from the start of the energy crisis in September 2021 to mid-2023 (Sgaravatti *et al.*, 2023).

This amount was allocated to various measures implemented by European countries (including EU members, Norway, and the United Kingdom) to protect consumers and businesses from rising energy prices.

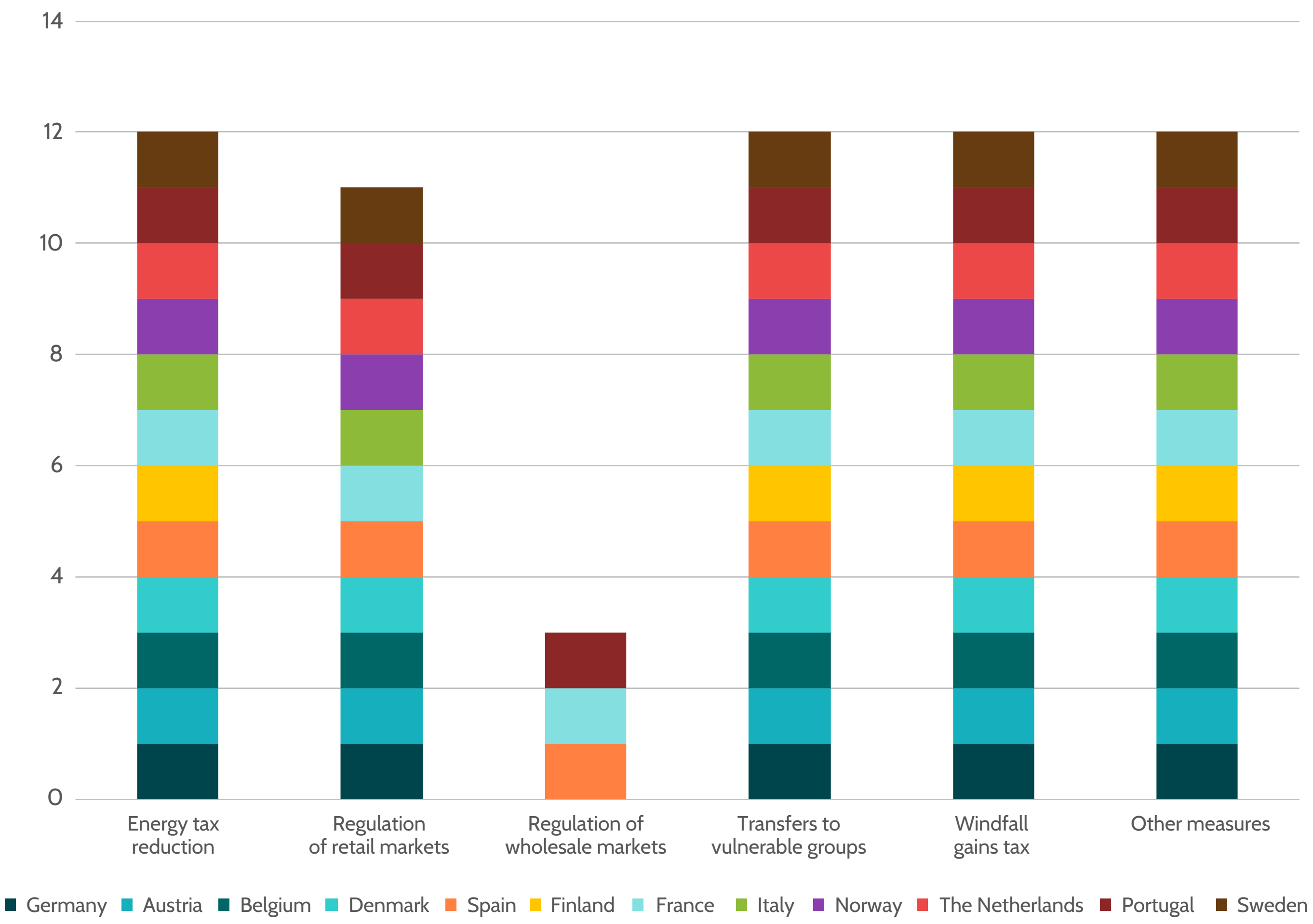
Most of these measures did not involve direct intervention in the wholesale energy markets, but focused on maintaining the purchasing power of consumers (see Figure 10). These strategies reflect a concern to find a balance between the need to alleviate the financial burden for consumers and respecting the pricing mechanisms in wholesale markets, as altering them could have unwanted side effects on the efficiency of the energy market. The recommendations of the European Commission (EC), presented in its document "Tackling rising energy prices: a toolbox for action and support," suggest that EU members should implement strategies that are aligned with the rules governing this association of countries and seek to mitigate the impact on the electricity bills of end consumers. Measures such as transfers to vulnerable groups, reduction of energy taxes,

[24] It should be noted that some of these measures, such as electricity tax reductions, were also implemented during the economic crisis resulting from the COVID-19 epidemic (Zakeri *et al.*, 2022).

postponement of electricity disconnections, and discounts on bills were implemented, benefiting predominantly the most vulnerable households.

Among the strategies outside the toolbox, as previously mentioned, was the regulation, through taxes, of the extraordinary profits of some electricity generators. The high electricity prices, derived from marginal units, meant that plants with lower variable costs, such as nuclear, wind, or solar, reaped considerable benefits. For example, Spain instituted a mechanism to reduce the revenues of non-carbon-emitting plants and established an initial tax on extraordinary profits. Non-carbon-emitting plants had to return revenues that exceeded what they would have earned if the gas price had been capped at €20 per MWh, according to an established formula (Batlle, Schittekatte, and Knittel, 2022a).

FIGURE 10. **Policies implemented by European governments in response to the energy crisis, 2021-2022**



Source: Own elaboration based on Sgaravatti *et al.* (2023).
Note: The figure shows the main measures employed by some European governments to contain the rise in energy prices and protect consumers. Measures such as reducing energy taxes aimed to decrease consumer electricity bills at the cost of lower fiscal revenue. Regulation of retail markets was implemented through the establishment of price caps. Wholesale market regulation included measures like subsidies for wholesale fuel prices. Taxes on windfall profits were aimed at reducing the revenues of non-thermal power plants.

In this crisis, the approach was to not intervene in the markets, or to intervene as little as possible. Long-term investments, such as those made in renewable energies, carry risks, the greatest of which is regulatory. Retroactive measures like taxes on extraordinary profits translate into impacts worth billions of euros, which damage regulatory credibility and increase the perception of risk. Among the risks of market intervention are the increase in financing costs and the possibility of litigation/arbitration by investors, which can consequently slow down and increase the cost of the energy transition (Batlle, Schittekatte, and Knittel, 2022b).

Some general lessons derived from the resource allocation during this crisis were as follows: focus supports to reduce fiscal impacts—prioritizing lower-income households and implementing these programs temporarily; include incentives to reduce energy demand; accelerate the deployment of solar and wind plants—to reduce vulnerability to increases in fuel prices; and increase energy security (Arregui *et al.*, 2022).

4.3 Discussions on wholesale market design

Given the volatility of short-term electricity prices and concerns about supply security, several governments highlighted the need to proceed with a reform of the wholesale electricity markets (Schittekatte and Batlle, 2023). In 2022, the EC convened a series of discussions for a structural reform of the electricity market. The main goal was to protect consumers from fluctuations in electricity prices by complementing short-term markets with a more pronounced role for long-term markets, fostering greater use of power purchase agreements, and facilitating investment in clean energies.

The main challenges that the wholesale electricity market must address according to the EC (2023) are the following:

- **Insufficient consumer protection mechanisms** against short-term price increases in electricity.
- **The excessive influence of short-term price increases, driven by rises in fossil fuel prices,** on electric rates.
- The low capacity for the **reduced cost of renewable energies to be reflected in electric bills.**
- **The impact of extreme volatility** and regulatory interventions on investment.
- **The lack of sufficient flexibility in non-fossil sources** and in terms of storage and demand response.
- **Reduced liquidity in forward contracts** in many member states.
- The limited capacity of consumers to choose contract types.
- **The difficulties in accessing renewable energy directly** through energy sharing.
- **The need for more robust market monitoring,** for better protection against market power abuse.

The EC maintains that its market model based on bids with marginal cost remuneration is efficient, as it motivates generators to minimize costs and present the most competitive bids. These bids are organized from the most economical to the most expensive, and the market price is set according to the cost of the last producer required to meet demand. This approach not only supports the transition towards decarbonization by prioritizing renewable sources for their marginal cost but also promotes flexibility, transparency, and competition. Additionally, the EC's integrated market is particularly equipped to address short-term supply security issues. When considering reforms in market design, the EC points out, it is essential not to lose sight of all these factors, as the electric system must continue to operate reliably while the economy is electrified, and the electricity sector is decarbonized. The EC also foresees that the incorporation of greater renewable generation will lessen dependence on natural gas prices. By 2030, renewable sources are expected to constitute more than two-thirds of the EU's electricity.

According to Batlle, Schittekatte, and Knittel (2022b), Fabra (2023), Schittekatte and Batlle (2023a), Zachmann, and Heussaff (2023), and the European Commission (2023), the most notable recommendations for improving the efficiency in the operation of wholesale electricity markets and increasing the resilience of these markets to exogenous factors that lead to a sustained increase in electricity prices in the EU are the following:

- **Enhance and focus efforts on building more efficient long-term markets** that enable the integration of variable renewable energies (VRE), reducing the impact of short-term markets on electricity tariffs.
- **Maintain the marginalist approach of the day-ahead market and the main regulations of short-term markets.**[25] High gas (or coal) prices will continue to drive up short-term electricity prices, but as renewable energies are integrated, their influence will diminish.
- **Improve data collection and market monitoring;** strengthen investigations; harmonize sanctions to provide more effective protection against market power abuse and ensure competitive market behavior.
- **Increase the liquidity of long-term contracts,** allowing more suppliers and consumers to hedge against drastic price fluctuations over longer periods.
- **Encourage long-term contracts** (over ten years), including contracts for differences and power purchase agreements (PPAs), to offer more stable prices to consumers.[26]
- Enhance the operation of forward markets (up to three years) to reduce exposure to price volatility.
- **Introduce new types of contracts,** such as Asian options, which are a centralized and regulated auction in which a central entity acquires long-duration call options from generators on behalf of a group of consumers. These "stability options" act as an automatic stabilizer, transferring generator profits during periods of sustained high energy prices to "protected" consumers. In exchange for this protection, these consumers pay a premium via electricity tariffs and avoid unexpected fluctuations in their monthly bills.
- **Regulate the prices facing end consumers in emergency cases** (subsidies up to a certain level of consumption), and regulate prices indirectly, such as with the use of vouchers for vulnerable populations.
- **Implement programs to reduce energy demand** during crises.
- **Promote flexibility:** generation with ramping capacity; demand management, essentially refining the price signals exposed to consumers (for example, hourly rates that reflect market prices, including prices for ancillary services); storage.
- **Accelerate the penetration of renewable energies,** including collective distributed generation. This would reduce the EU's dependence on external agents and thus also reduce energy prices, albeit with increased volatility.
- **Address the flexibility of markets,** which appears more vulnerable with the integration of more renewable energy sources. The EC suggests adjusting the schedule for closing cross-border intraday operations to bring it closer to the actual time. Allowing bids minutes before electrical dispatch instead of hours would enable market actors to transact as close as possible to the real-time supply of electricity, optimizing the use of renewable energies and reducing imbalance costs. A flexible system, with adaptable energy generation, efficient storage, and consumers who adjust their demand, can stabilize prices and integrate more renewable energies.

[25] Long-term investments, especially in renewable energies, present risks that may discourage investors. Regulatory risk refers to possible changes in the regulatory environment and interventions in wholesale markets such as windfall profit taxes. Measures that damage confidence in the regulatory framework can slow down the energy transition and make it more costly.

[26] The energy crisis has shown that many suppliers were not well protected against an increase in wholesale prices. Instead, these suppliers had relied on buying in the short-term wholesale market even when they offered retail contracts to their customers with a term of one year or more. The reason these providers did not cover their positions may, of course, be that their experience was that coverage was unnecessarily expensive; after all, coverage has a cost.

The recommendations associated with the integration of renewable energies mentioned earlier align and complement the initiatives of the European Green Deal and the decarbonization goals of the REPowerEU Plan.

Discussions on more profound reforms, which had already begun for different reasons such as the high penetration of variable renewable sources, mainly solar and wind, have also resumed (Fabra, 2023). The EU's Internal Electricity Market has focused more on short-term transactions and has left long-term decisions to national regulations, similar to the Regional Electricity Market in Central America.

In the context of the debate on the structural reform of electric markets, several proposals for the EU's Internal Electricity Market were presented. The most radical include:

- **For the short-term market,** the implementation of a pay-as-bid model in replacement of the marginalist model.
- **The separation of the market into two:** one for variable energy (photovoltaic solar and wind) and another for firm energy (nuclear, coal, gas).

The two most popular pricing strategies are pay-as-bid and marginal pricing. As shown in Chapter 2, these pricing strategies have unique characteristics and advantages that make them suitable for different contexts. The pay-as-bid model has been recognized for several decades as a model suitable for implementation in contexts of very high electricity prices, which can arise from possible abuses of dominant positions, but also as a result of a lack of generation capacity (Willems and Yu, 2022). One of the main criticisms of the marginalist model in the recent European crisis was that, ideally, a reform was needed that linked market prices to an average price, rather than to the marginal price (Batlle, Schittekatte, and Knittel, 2022a; Pollitt *et al.*, 2022).

The main argument of those proposing the implementation of the pay-as-bid mechanism is that inframarginal generators receive excessive rents.[27] When generators in a marginalist market have total freedom to set their selling offers based on commercial strategies and not on their actual costs, the abuse of dominant positions can result in increased prices. The electricity market of England and Wales is probably the one that has undergone the most reforms, always with the intention of avoiding abuses of dominant position in generation and thus protecting consumers; another relevant case is the California electricity market. However, in a marginalist market based on economic dispatch and where generation bids are based on variable costs, the revenues of inframarginal generators are indispensable for the recovery of investment costs, as shown in Annex A. Otherwise, bids should explicitly reflect investment costs, which would lead to potentially very costly distortions of economic dispatch, as also shown in Annex A.

Another controversial proposal circulating within the EU is to split the market according to the technology involved: one market for renewable technologies and another for conventional energies (Keay & Robinson, 2018). This proposal involves creating two markets based on the type of energy: "as available" and "on demand." Intermittent plants—solar and wind—would participate in the first market with remuneration equivalent to their long-term marginal cost trend or levelized cost of electricity. The on-demand market would act as a market that, achieving a balance between supply and demand in the system, would dispatch firm plants according to their merit order. Both prices would be reflected in the supply rates. On the demand side, consumers would have the option to choose the market in which they wish to participate, or a combination of both.

The proposals in the EU do not detail aspects of their implementation; for example, the use of the transmission network associated with each of the proposed markets. However, there are experiences in other regions regarding the practical implementation of overlapping electric markets that use the same transmission network, such as the Regional Electricity Market of Central America, where seven markets coexist on the same transmission network: six national and one regional. The proposal to modify the Industry Law in Mexico, which considers two sequentially executed markets not for technological reasons but due to ownership issues, has also been extensively analyzed.

[27] Although the pay-as-bid model has not been explicitly considered in the proposals (Schittekatte and Batlle, 2023a), the implementation of this model has been regarded by some academics as an additional measure that would help reduce the volatility of the electricity markets.

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The execution of two sequential markets presents the following problems:

- **The first dispatch is necessarily myopic,** as it does not have information about what the second market offers, which can cause unnecessary congestion.
- **The second dispatch presents a reduced feasibility region,** due to the use of the transmission network by the first dispatch, and can raise issues little explored in terms of prices, such as negative prices caused by "counterflows" relative to the flows caused by the first dispatch.

This inevitably results in suboptimal use of the transmission network, and prices could lack economic sense. Of course, there are other implementation alternatives for two dispatches; for example, co-optimized in a single mathematical model.

It is important to emphasize that a similar result to that associated with the proposal for two markets has been achieved with the realization of auctions for renewable energies; buyers/consumers effectively pay the prices of the contracts implied in the auctions. **In the EU, the idea of establishing two markets arises from the perception that the current (marginalist) design is inadequate (Schittekatte & Batlle, 2023a), especially in a market with a high penetration of variable renewable energy generation.**

5

SHORT-TERM ELECTRICITY MARKETS IN LATIN AMERICA AND THE CARIBBEAN

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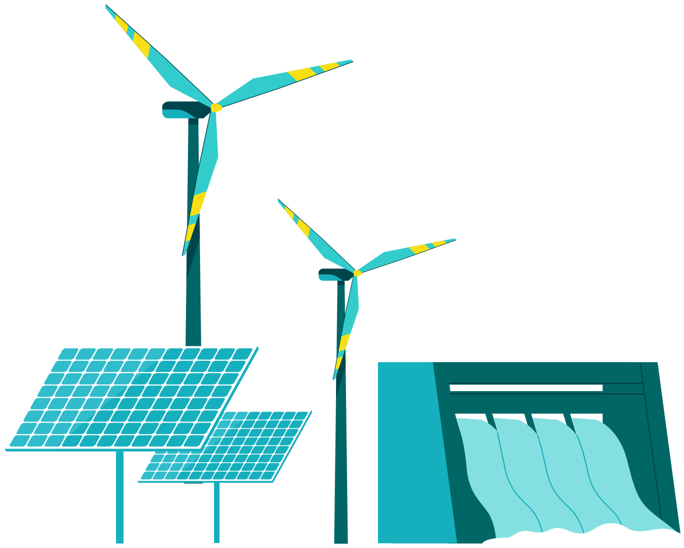

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SHORT-TERM ELECTRICITY MARKETS IN LATIN AMERICA AND THE CARIBBEAN

Wholesale electricity markets in Latin America and the Caribbean are highly diverse in terms of their organization. This diversity is manifested in models ranging from wholesale competition with a predominance of private participation to vertically integrated schemes, where the State retains majority control. Approximately half of the countries in the region have adopted wholesale competition models that include short-term markets.

Given the varying designs of wholesale markets across the region and the diversity of electricity generation mixes, short-term electricity prices exhibit a wide range of behaviors. Although most of these are cost-based markets, the diversity of energy sources and market design means that each country responds uniquely to different circumstances. In some countries, short-term electricity prices are closely linked to the price of natural gas, while in others, climatic factors, such as droughts or heavy rains, have a considerable impact on prices.

It is important to note that each market is at a different stage of development, which presents specific challenges for each country.

There are common challenges throughout the region, however, such as the integration of variable renewable energies (VRE), rising fuel prices, and climate change impacts. These challenges underscore the urgent need to diversify energy sources, update market designs, and strengthen regional collaboration.

This chapter focuses on analyzing the distinctive characteristics of short-term markets in eight countries, as well as the factors that influence their price formation. The main objectives of the chapter are to: 1) identify the fundamental characteristics of these markets in the region; 2) to determine the key factors that impact prices in the short term; and 3) identify the challenges faced by these markets.

5.1 Short-term electricity market design in Latin America and the Caribbean

Starting in the 1980s, many countries in Latin America and the Caribbean embarked on a profound reform of the electricity sector. The deregulation of electricity generation led to the creation of wholesale electricity markets and fostered greater competition. These transformations were motivated by the operational inefficiencies of companies with vertically integrated structures, the inability of the public sectors to finance the necessary investments and infrastructure maintenance, and the imperative need to alleviate fiscal stress stemming from the state's commitment to the provision of electricity services (Besant-Jones, 2006; Gratwick & Eberhard, 2008).

Each country has undergone its own reform process in the electricity sector, but with the common objective of increasing competition and improving economic efficiency in a scenario of vertically integrated companies. Reforms have not been a static process but have evolved dynamically in response to each country's economic landscape and energy needs. The reform process in Latin America and the Caribbean began in Chile in the 1980s. In 1992, Argentina adopted reform measures in its electricity sector, followed by Bolivia, Colombia, and Peru. In the second half of the 1990s, countries such as Brazil, El Salvador, Guatemala, and Uruguay reformed their electricity markets (see Table 4).

These reforms promoted the creation of regulatory bodies to ensure the efficient management of short-term electricity markets. Nevertheless, vertically integrated business models or models with limited private participation persist in several countries in the region. This report analyzes the short-term markets of eight representative countries in the region, where wholesale market competition has been implemented.

As shown in Table 5, there is a great disparity in the size of the electricity markets of the eight countries analyzed. Brazil, with significantly higher installed capacity and electricity generation, is positioned as the largest electricity market in the region. In contrast, El Salvador has a much smaller market, with a significant dependence on electricity imports. Differences in the size of electricity markets are largely explained by different population sizes, level of economic development, and availability of energy resources. Countries with larger populations and higher levels of industrialization, such as Brazil and Mexico, tend to have larger electricity markets. On the other hand, smaller economies such as El Salvador tend to have smaller electricity markets.

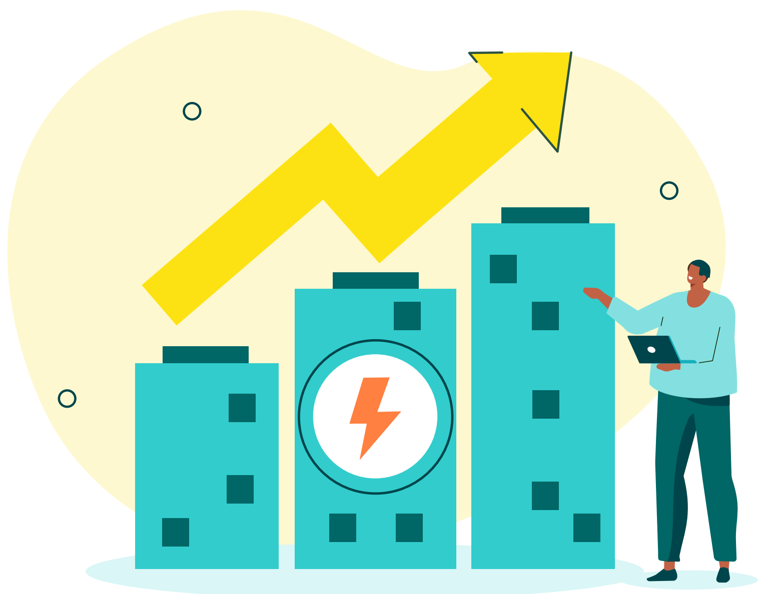


TABLE 4. Structure of the wholesale electricity market in Latin American and Caribbean countries

Country	Market Structure	Year of Implementation of the wholesale competition model
Argentina	Wholesale Competition	1992
Bahamas	Vertically Integrated Company	
Barbados	Vertically Integrated Company	
Belize	Single Buyer Model	
Bolivia	Wholesale Competition	1996
Brazil	Wholesale Competition	1998
Chile	Wholesale Competition	1989
Colombia	Wholesale Competition	1995
Costa Rica	Single Buyer Model	
Dominican Republic	Wholesale Competition	1999
Ecuador	Single Buyer Model	
El Salvador	Wholesale Competition	1998
Guatemala	Wholesale Competition	1998
Guyana	Vertically Integrated Company	
Haiti	Single Buyer Model	
Honduras	Single Buyer Model	
Jamaica	Single Buyer Model	
Mexico	Wholesale Competition	2014
Nicaragua	Wholesale Competition	1998
Panama	Wholesale Competition	2014
Paraguay	Vertically Integrated Company	
Peru	Wholesale Competition	1994
Surinam	Vertically Integrated Company	
Trinidad and Tobago	Single Buyer Model	
Uruguay	Wholesale Competition	1997
Venezuela	Vertically Integrated Company	

Source: Prepared by the authors based on Akcura (2024).
Note: In most wholesale competition markets in the region, electricity is traded through bilateral contracts and a spot market based on audited costs. Colombia operates through bilateral trade and a bid-based spot market. Despite having implemented a wholesale market more than two decades ago, Uruguay has retained a high degree of concentration in the electricity sector, where the state-owned UTE has been the main purchaser of energy. One of the main causes of this situation lies in regulatory barriers, including the requirement to provide firm power, which have hindered the participation of private producers. The Single Buyer model refers to a scheme in which a single buyer purchases all the electricity generated, whether or not it owns or controls generation assets. In the case of a Vertically Integrated Company (VIC), the electricity utility controls the generation, transmission, and distribution of electricity. This company may be majority privately owned or privately managed, even if the assets are state-owned.

TABLE 5. Capacity, generation, and cross-border electricity trading in LAC electricity markets, 2022

Country	Capacity (GW)	Generation (GWh)	Import (GWh)	Export (GWh)
Argentina	42.9	145,057	6,310	31
Brazil	206.4	677,133	17,887	4,979
Chile	33.2	83,210		
Colombia	18.8	76,905	159.2	465.3
El Salvador	2.8	6,383	706.0	338.3
Mexico	87.1	333,963	79.2	0.1
Peru	15.7	59,745	32	4
Uruguay	4.7	12,784	31	1,366

Source: Prepared by the authors based on annual reports from the country's electricity regulator or energy secretary.

As outlined in Chapter 3, wholesale electricity markets are predominantly divided into spot and forward markets. The spot market reflects real-time electricity transactions and can experience significant fluctuations due to immediate supply and demand. Forward markets, which can be regulated or free, offer contracts for the future delivery of electricity, thus providing greater stability and mitigating the risks inherent in the volatility of the spot market. This subsection will explore the main characteristics of the spot markets of the selected countries.

The relevance of short-term markets varies significantly among countries in the region. For example, in Colombia, 22% of the energy traded was traded in the short-term market or Energy Exchange in 2022, while in Mexico, 22% of the energy required for the Basic Services Supplier, or low demand users, was traded in these markets. In Uruguay, 7.8% of the total energy traded was through the spot market, and in El Salvador, 23% of energy is traded in this market, known as the System Regulatory Market. This diversity is largely explained by differences in each country's generation structure, demand, and regulatory framework. Nevertheless, it should be noted that a higher volume of transactions in these markets may generate greater volatility in electricity tariffs, which requires more sophisticated risk management mechanisms.

The reforms implemented in Latin American and Caribbean electricity markets have led to greater diversity in market designs. Although most countries have adopted cost-based models, there are significant differences in price formation mechanisms. A unifying feature among this diversity is the presence of wholesale electricity markets operating on short-term horizons and the existence of independent operators and regulators. These market operators and regulators supervise and guarantee the proper operation of the markets. Table 6 shows the main characteristics of short-term wholesale market designs in eight countries in the region. The integration of variable renewable energies has posed new challenges for market operators, who must develop tools and mechanisms to manage volatility in generation and ensure a secure supply.

The adoption of single settlement markets has predominated in the region, complemented by the implementation of the audited marginal cost method. **The factors that have led to the adoption of audited costs in the region include the following:** increasing transparency, ensuring efficient dispatch at hydroelectric power plants, and avoiding market power problems associated with auction methods (Barroso *et al.*, 2021). Countries such as Argentina, Bolivia, Chile, and Peru implemented the audited marginal cost dispatch model, while Colombia uses a bidding model that operates under the marginal price logic. Mexico has a hybrid system, in which participants can submit bids that are within a certain range of their audited costs. Market operators become more relevant in an audited cost system since they audit all generation parameters and variable costs of each generating plant to estimate their marginal costs. The value of water is estimated based on a series of assumptions and with the help of stochastic optimization models.

According to Ribeiro *et al.* (2023), in countries with cost-based markets—dominated by hydropower—the active participation of the operator prevents price manipulation by upstream plants and protects downstream plants. Yet constantly updating reserve information comes at a high cost, and calculating the value of water proves to be a challenge. If the operator manages the generation and determination of water values, any discrepancies in the assumptions by which the operator estimates the value of water may lead to legal disputes. Although a bidding system decentralizes responsibility to participants, regulators have been cautious in adopting such a system because of its high costs and the challenges of mitigating market power in bid-based markets (Barroso *et al.*, 2021).

In Argentina, the electricity market operates under a cost-based model with a single settlement structure, with hourly dispatch. The entity in charge of managing the wholesale electricity market, CAMMESA, acts as the Dispatch Body (OED) for the Argentine Interconnection System (SADI). The OED is tasked with calculating energy spot prices. In Argentina, there is a tolling system where the regulator sets electricity prices and determines the reference prices for fuel, in order to dampen the volatility inherent in spot prices. This stabilized pricing system is called seasonal pricing. Set every six months, this scheme seeks to protect electricity distributors from sharp price fluctuations.

Brazil's electricity spot market is overseen by the market operator, the Câmara de Comercialização de Energia Elétrica (CCEE). The Brazilian spot market operates through a single settlement system, in which dispatch is based on audited costs and the market price for four zones is determined ex ante. As of 2020, prices are determined one day ahead, for each hour; this change arose from the increasing integration of solar and wind energy into the system.

The marginal cost of hydroelectricity is based primarily on the opportunity cost of water stored in reservoirs, determined by factors such as the projected behavior of hydroelectric inflows, the expected dispatch of other generators, the marginal cost of on-line thermal generators, and the cost of any shortfall to consumers (Hochberg & Poudineh, 2021).

Since 2011, El Salvador has adopted a cost-based market with a single price, replacing a bid-based system. The spot price is calculated for each hour based on the short-term marginal cost, which corresponds to the variable cost of the last unit generated. This market has a single settlement system. The market operator, the Transaction Unit (TU), manages the system's daily program, adjusting offers and demands—overseen by an intersectoral commission—, and guarantees the continuity and security of the electricity supply. El Salvador, together with five other countries in the region, belongs to the Regional Electricity Market (REM). Wholesale market transactions are carried out in the Regional Contract Market or in the spot market called Regional Opportunity Market (ROM). The operator for this regional market is the Regional Operating Entity (ROE). The short-term auction-based market operates through daily injection and withdrawal bids at the nodal level. Transactions in the ROM are the product of a regional pre-dispatch that takes place the day before and real-time trading. Before pre-dispatch in the REM, the national markets carry out a pre-dispatch according to the rules of each country, without considering imports or exports, and from this pre-dispatch, the regional pre-dispatch is carried out based on countries' energy injection or withdrawal bids.

In Peru, the *Comité de Operación Económica del Sistema* (COES) regulates a nodal cost-based market, acting as an operator independent of the system. Real-time dispatch is based on variable costs' merit order, resulting in a wholesale spot price that is determined ex post. Every half hour, marginal prices are calculated at more than one hundred nodes, factoring in the cost of energy, network congestion, and losses. The spot market there is organized as a "mandatory pool"; generators supply all the energy and users draw according to their need, regardless of the specific generator with which they may have a contract.

In Uruguay, the spot market reconciles surpluses and shortages arising from dispatch and operation against contractual commitments and actual consumption. This market operates on a daily and hourly pre-dispatch basis, also with single settlement, and prices are determined ex post. The *Administración del Mercado Eléctrico* (ADME) is the public entity in charge of managing the wholesale electricity market and the operation of the National Load Dispatch.

Chile's wholesale electricity market is based on audited costs with a uniform price mechanism (pay-as-clear). The spot market operates with nodal prices determined ex post and hourly. In the audited cost market, power plants provide the Chilean *Coordinador Eléctrico Nacional* (National Electric Coordinator, or CEN) with the technical characteristics of their units and the input contracts—such as natural gas—, with their respective prices. From this information, CEN calculates the start-up cost and the variable operating cost of each unit on a daily basis. Through this cost breakdown, the demand, and its network model, CEN determines the lowest cost dispatch considering transmission constraints.

In Colombia, the exchange price is established hourly and ex post, based on the bids of the generating units and the remaining demand, taking into account the potential demand of the system and the demand to be covered by bilateral contracts. All units must bid each day, indicating the price and capacity for the following day, and specify a start-up cost on a quarterly basis. The *Centro Nacional de Despacho* (CND) organizes the auction, defining a daily generation program that covers the demand at the lowest cost. The hourly spot price is determined by the unit dispatched with the highest price, and all units receive this price for their production. The prices are for a single settlement.

In Mexico, the *Centro Nacional de Control de Energía* (CENACE) functions as an independent operator, in charge of dispatching generation and coordinating the operation of the transmission network. The short-term electricity market operates under a cost-based nodal pricing design, with a system comprising about 2,500 nodes. The companies provide CENACE with technical details about their generation plants. Based on this information and using a fuel price formula, CENACE estimates the marginal production cost for each plant. Every day, these companies send out quantity and price offers for the next day's market. Before determining the dispatch, CENACE contrasts the price offered with the estimated marginal cost and discards offers that vary by more than 10% with respect to the cost. Each node is assigned an hourly price that reflects the marginal cost of covering a 1 MWh increase in demand at that node. Mexico is the only market in the region with a real-time market and a day-ahead market.

TABLE 6. Key characteristics of short-term markets in Latin America and the Caribbean

Country	Granularity (spatial)	Granularity (temporal)	Type of short-term market
Argentina	Single	Single settlement	Audited marginal cost
Brazil	Zonal	Single settlement	Audited marginal cost
Chile	Nodal	Single settlement	Audited marginal cost
Colombia	Single	Single settlement	Bid-based market
El Salvador	Country: Single REM: Nodal	Country: Single settlement REM: Multiple settlement	Country: Audited marginal cost REM: Bid-based markets
Mexico	Nodal	Multiple settlement	Hybrid
Peru	Nodal	Single settlement	Audited marginal cost
Uruguay	Single	Single settlement	Audited marginal cost

Source: Prepared by the authors.

Despite considerable progress in optimizing pricing mechanisms in short-term markets, the region's electricity markets still face challenges in limiting extreme volatility and mitigating market power. The tools developed to address this problem include price caps, market competition monitoring, cross-border interconnections, and long-term markets.

As in the U.S. electricity markets, a strategy adopted by some countries in the region is to implement price caps for short-term electricity prices in order to avoid the exercise of market power in times of market stress. In the Uruguayan wholesale market, for example, the spot price is determined based on the marginal cost of the cheapest option among the available generation units that do not need to be dispatched. There is a restriction, however: if that price exceeds US$250 per MWh, the spot price is automatically set at that US$250 per MWh ceiling. In Argentina, where natural gas has both domestic and imported sources (LNG, Bolivia), the price is defined internally, according to a gas market policy. This country established a maximum spot price (Resolution 323/2023), which in this case is set at AR$ 2.691 per MWh in periods where the risk of projected outages is very low. Similarly, in Brazil, the marginal cost, known as the Price for Settlement of Differences (PSD), has established maximum and minimum limits.

Despite the reforms introduced, electricity markets in Latin America and the Caribbean still face obstacles derived from oligopolistic structures and market power concentrations, which result in higher prices in short-term markets compared to what would be observed in competitive markets. Another underlying challenge is the presence of transmission infrastructures that are inadequately sized to sustain effective wholesale competition. It is therefore essential for electricity markets to have clear rules, appropriate market structures, and robust regulation. And if the rules of the game are not adhered to, penalties must be severe enough and applied consistently enough to discourage non-compliance and ensure transparency and fairness (Wolak, 2003).

Fluctuations in water cycles can also lead to periods of scarcity and give certain stakeholders the opportunity to exert their influence on the electricity market to raise prices. McRae & Wolak (2017) have analyzed prices in the Colombian electricity market during water stress events caused by El Niño phenomena in 2009 and 2015. They found that prices in 2015 were considerably higher than in 2009, even though the electricity market experienced similar conditions. They determined that this disparity was mainly due to the ability of certain stakeholders to exercise market power, derived from the fact that investment in new energy generation was lower compared to the increase in demand.

Several countries have adopted measures to limit the exercise of market power by the main stakeholders in wholesale markets.

In 2018, Mexico implemented the Market Surveillance Manual, focused on monitoring the operation of the MEM and the behavior of its participants, with the goal of guaranteeing market efficiency and respect for the rules in force. For example, it seeks to establish alliances with the Federal Economic Competition Commission to combat monopolistic practices. Although Mexico operates under a bid-based market scheme with ranges around audited costs, it is not exempt from the exercise of market power. McRae (2019) has shown that schemes of this type do not completely eradicate these abuses, and uses as an example, precisely, the conduct of the main generating companies in the Mexican electricity market. The author suggests that there are at least two strategies by which actors can manipulate the market: the strategic alteration of input prices, mainly fossil fuels, and the tactical management of power plant availability through the interruption of their operations.

In Chile, in the mid-2000s, significant steps were taken to foster competition in the energy sector: a thorough regulatory review was completed (Serra, 2022), including the oversight of transmission and distribution networks; sectoral entities were consolidated; and auction rules were modified to increase the number of participants willing to supply energy to regulated consumers. Despite these efforts, the market saw limited entry of new generators, primarily due to a slowdown in the construction of conventional power plants. This stagnation was driven by stricter environmental regulations and increasing public opposition. As a result, energy prices rose until the situation shifted with declining costs for solar and wind energy technologies. Supported by incentive policies for renewable energy, this change paved the way for more competitors to enter the market, ultimately leading to a downward trend in prices.

Chile also established the *Unidad de Monitoreo de la Competencia* (Competition Monitoring Unit, or UMC) to supervise antitrust practices in the energy sector. Its main objective is to ensure that prices reflect actual energy shortages and avoid distortions caused by some companies' market power. The UMC evaluates aspects such as fuel availability, technical parameters, transmission tenders, and other relevant factors. It also investigates specific situations of the National Electricity System (SEN) based on its own findings or third-party reports. If it detects possible antitrust violations, the UMC refers the information to the National

Economic Prosecutor's Office for investigation. According to the latest UMC report, as of December 31, 2022, the Herfindahl-Hirschman Index (HHI) at the national level, with no time or subsystem distinction, registered a value close to 1.001. At first glance, this might suggest that the market is deconcentrated, but when analyzing the distribution of the HHI per hour and considering each subsystem between January and December 2022, it becomes clear that market concentration is in fact medium or high. The report notes that the main strategies through which market power can be exercised are the physical or economic withholding of capacity and the manipulation of fuel prices.

Colombia has also implemented mechanisms to promote competition in the electricity sector. The market share of a generating company is determined by considering the firm energy of all its plants and dividing it by the total firm energy of all the generating companies in the country. In parallel, the HHI is used to evaluate the level of market concentration. According to current regulations, if a company's participation in generation is between 25% and 30% and the HHI is higher than 1800, the company will be under special supervision by the Superintendency of Residential Public Utilities (SSPD). In the event that a company's share exceeds 30% of generation and the HHI is greater than 1800, it will be obliged to release sufficient energy to other market agents, in order to reduce its share to below the established limit.

The role of long-term markets

> Wholesale markets typically include a segment for long-term contracts, which can be either regulated or freely negotiated.

Long-term contracts do not directly affect economic dispatch, and in some cases remain independent of the prices set in short-term markets. In Colombia, for example, there is a market for long-term bilateral contracts, with the participation of various agents and of an essentially financial or hedging nature, which means that they do not influence the commercial operation of the spot market or determine the actual dispatch of energy. In contrast, in Brazil, short-term pricing is closely linked to the free energy market, which serves as a key reference point for price determination within the market.

Although Latin America and the Caribbean have made progress in the implementation of short-term electricity markets, in many cases they are not the main channels for electricity trading; as in the markets of developed countries (Wolak, 2003), long-term contracts are the most relevant. One notable example is Peru, where the most significant wholesale electricity market is the bilateral contract market, followed by the spot market. The structure of the Peruvian electricity market mandates that all distributors enter into contracts with generating companies to secure their electricity supply, encompassing both energy and capacity requirements (Rudnick & Velasquez, 2019).

Similarly, El Salvador's Technical Unit (2023) reports that in 2022, 73% of energy was traded through contracts, which include bilateral, free competition, and public agreements. In contrast, only 27% of the energy was traded through the short-term market. In Brazil, the spot market and the free contract market have historically been less relevant than the regulated long-term contract market, where most of the country's energy is traded (Hochberg & Poudineh, 2021). **The potential effect of short-term market volatility on retail electricity prices will depend on two main factors:** first, the volume of energy traded in these markets; and second, whether these spot market prices are used as a reference in other submarkets.

Although trading volumes in short-term markets are often limited, prices of highly liquid long-term contracts reflect spot market price expectations (Schittekatte & Batlle, 2023b). When spot market prices are inefficient, they can create distortions throughout the market chain and lead to additional costs. These inefficiencies ultimately influence investment decisions and the selection of technologies within the electricity sector.

> Long-term electricity auctions have been key to the expansion of the electricity sector in Latin America and the Caribbean.

Launched in the 2000s in countries such as Brazil, Chile, Colombia, and Peru, these auctions were initially designed to promote private investment and maintain the security of supply of the electricity system. Over time, they have taken on an essential role in the development and expansion of the regional electricity industry. They have not only solved previous investment problems, but also played an important role in improving market liquidity and efficiency (Barroso *et al.*, 2021).

Recent literature strongly recommends complementing short-term electricity markets with mechanisms that guarantee investments in capacity and flexibility in the long term. (Munoz *et al.*, 2021; Ribeiro *et al.*, 2023). A country's installed capacity becomes especially relevant in critical situations and in the face of rising demand, scenarios in which a limited supply of energy translates into higher prices in short-term markets. There are mechanisms in place that seek to reward the capacity to meet energy supply in situations of peak demand or supply restriction. They are designed to reinforce market signals, offering additional remuneration that stimulates investment in generation, thus ensuring reliability of supply. These mechanisms include capacity requirement markets, which force the purchase of certain capacity to meet demand; capacity charge markets, which remunerate generators for the availability of their assets; and the reliability charge, which remunerates generators for maintaining supply at critical times.

In countries where hydroelectric generation predominates, mechanisms have been created that provide special remuneration for energy generation during periods of drought. These mechanisms, called firm energy mechanisms, operate in Brazil and Colombia, for example.

Various solutions have been implemented in Latin America and the Caribbean to guarantee the security of the supply of the electricity system, solutions that are particularly relevant in a context in which, following the introduction of renewable energies such as solar and wind, the spot market price in certain periods is close to zero. Mexico, for example, has created the *Mercado para el Balance de Potencia,* an annual market designed to reflect the shortage or excess of generating capacity through price signals. Its purpose is to ensure that the National Electric System (SEN) has sufficient capacity to cover periods of maximum annual demand.

In Colombia, a reliability charge is added to the wholesale price of energy. This charge acts as an incentive to secure future generation and guarantee long-term supply, especially during periods of drought. Chile has implemented a mechanism that operates through capacity payments, granted to generation units based on an administrative estimate of capital costs. This reference is adjusted proportionally according to the rated capacity, modulated in turn by an availability factor.

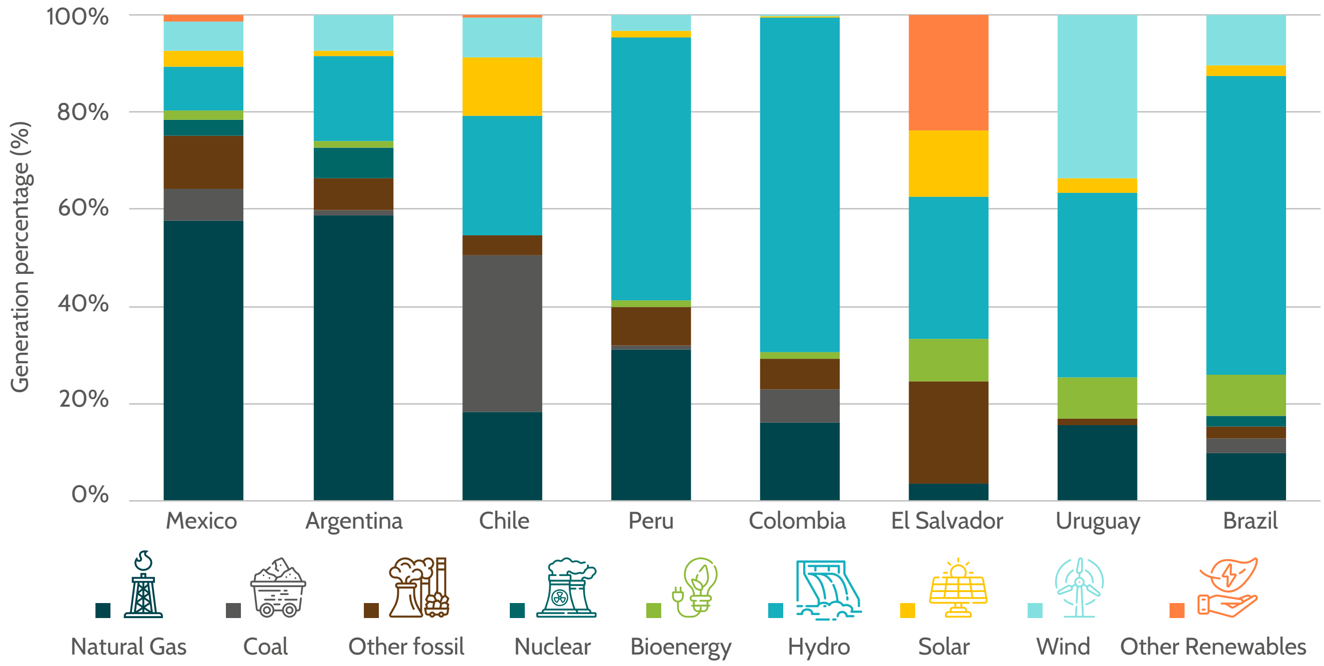
5.2 Short-term market volatility experienced in Latin America and the Caribbean

Diversity in the structure of the electricity sector in the region— in terms of the electricity matrix itself, wholesale markets, regulations, and intervention policies—leads to different results in the face of external shocks. The most recent crisis, derived from natural gas price increases, stressed the markets differently in each country. In Europe, electricity prices increased evenly in most countries, but Latin America and the Caribbean experienced mixed impacts. One of the main reasons that gas prices in Latin America and the Caribbean did not increase to the extent that they did in European countries is that markets are regionally segmented given the infrastructure requirements for transportation, such as pipelines and LNG import and export terminals.

The extent of the impact was closely related to the use of the marginal cost method—i.e., marginal plants set spot electricity prices—adopted by short-term wholesale electricity markets in the region. As low-cost renewable energy sources, such as hydro, wind, and solar, become more prevalent in the electricity supply mix, more expensive generation plants, such as those based on fossil fuels, are being displaced or relegated to a marginal role across the region. This phenomenon is known as the merit order effect (see Annex A).

Countries with a higher proportion of renewable energies suffered a lower impact. In these circumstances, inclusion of such sources may contribute to the lowest cost plants becoming the marginal ones. Figure 11 shows the composition of the electricity matrix in a set of Latin American and Caribbean countries between 2019 and 2022, revealing a remarkable variability. For example, in countries such as Argentina and Mexico, more than 50% of electricity comes from natural gas, while in Colombia and Brazil hydroelectric generation exceeds 50%.

FIGURE 11. Electricity matrix of LAC countries, 2019-2022



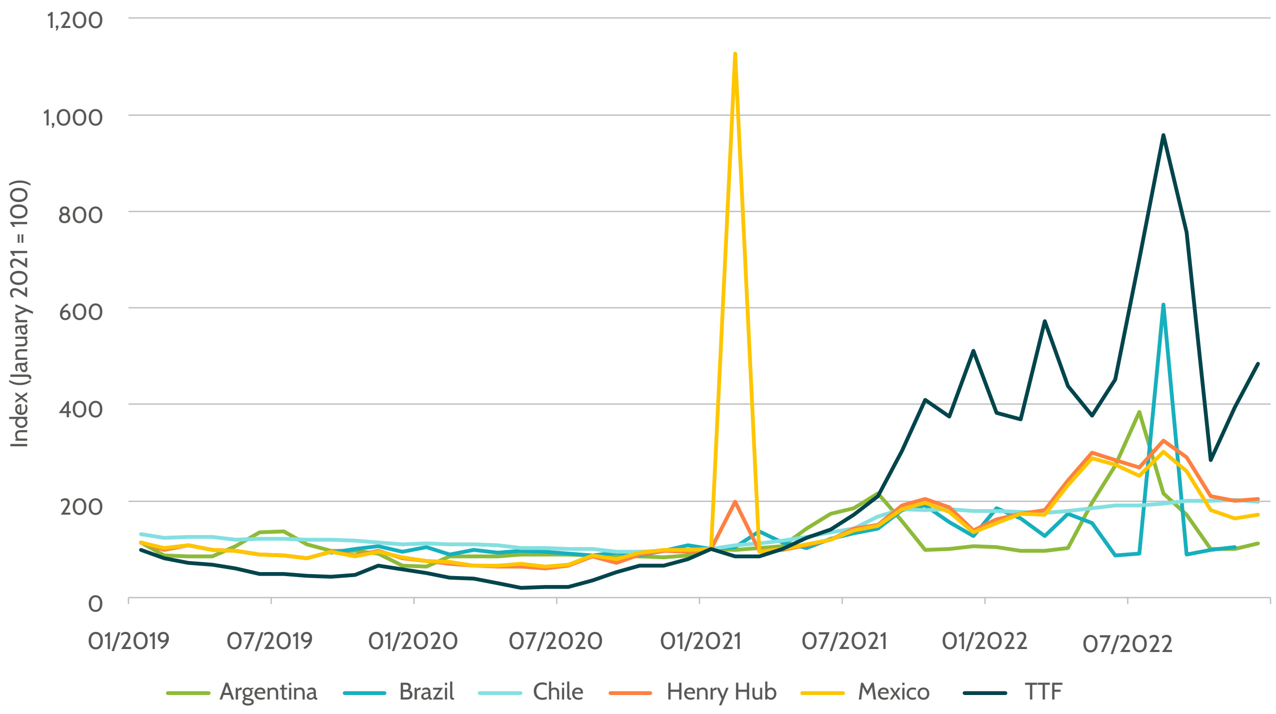
Source: Prepared by the authors with data from EMBER (2023).
Note: The figure shows the average percentage of generation by technology for selected LAC countries. There is wide heterogeneity among countries. Mexico is the country with the highest use of fossil fuels; Brazil has the cleanest energy matrix.

The natural gas market is segmented, so natural gas prices are initially determined at a regional level, applying different formulas, and using other fuels such as oil as a reference. Since the European natural gas market has gained traction in the global markets, however, many countries have taken the TTF natural gas price—the most important natural gas hub in Europe—as a reference, resulting in most importing countries seeing an increase in their prices (Pescatori *et al.*, 2022). On the other hand, while North American natural gas is highly influential, especially in Mexico, its impact is still limited in global LNG markets. Moreover, in producing countries such as Bolivia and Peru, domestic natural gas prices are often decoupled or partially regulated with respect to international markets, especially in the case of Bolivia, where gas for electricity generation has prices tightly controlled by the government.

The influence of the European natural gas price was evident in gas prices in Latin America and the Caribbean during the last volatility episode.

Figure 12 shows the prices of the main markets in Latin America and the Caribbean between 2019 and 2022. It is noted that monthly natural gas prices during the two years prior to the pandemic were relatively stable, but by mid-2021, and primarily in 2022, many markets underwent substantial increases, albeit each with its own dynamics. For example, natural gas prices increased significantly in the United States and Mexico in February 2021 due to weather events that affected the availability of the resource (as explained in subsection 5.6). This price increase is greatly

FIGURE 12. **Natural gas price indexes in Latin America and the Caribbean, 2019-2022**



Source: Prepared by the authors with data from LAC wholesale markets and Federal Reserve Economic Data (FRED).
Note: The figure shows an index of average monthly natural gas prices in the region. LAC prices are averages of the natural gas prices that electricity generating plants paid per month.

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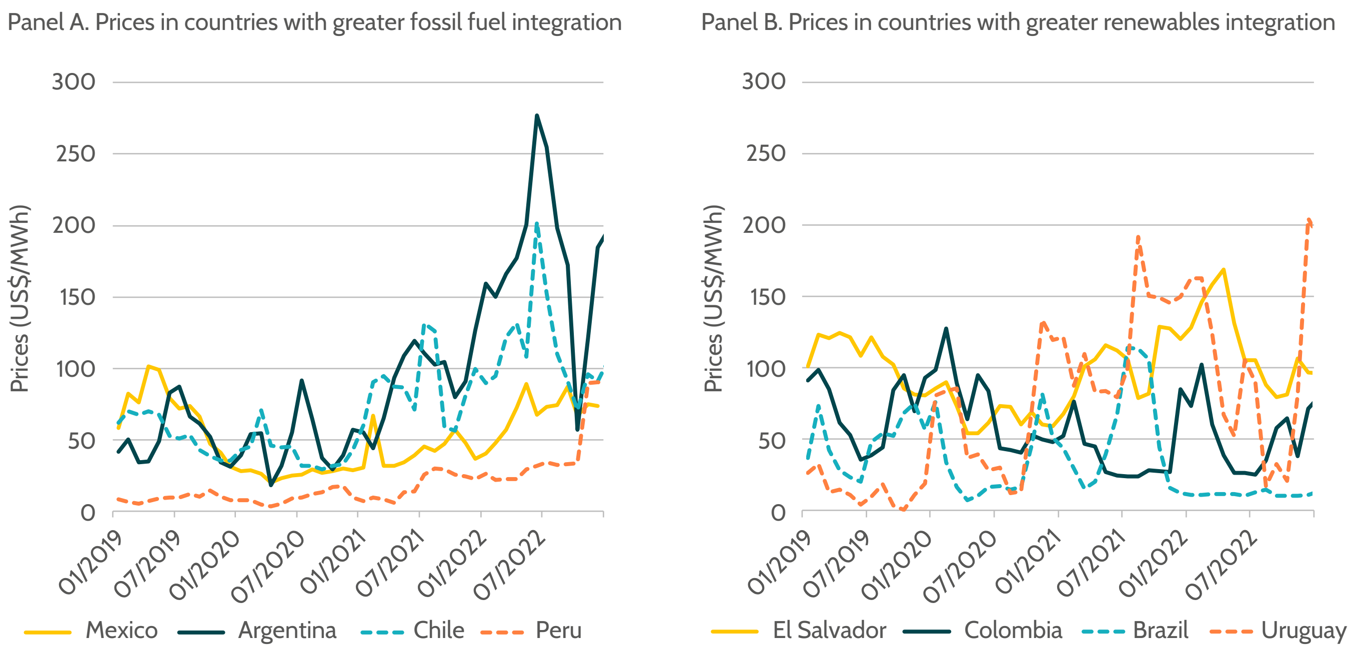
relevant to the electricity sector. In many cases, natural gas plants turn out to be the marginal plants that determine short-term market prices, especially at times of lower renewable energy generation and during periods of high demand, so the impact was often passed on to electricity prices.

Countries with an electricity matrix more dependent on fossil fuels experienced higher price increases than those with greater use of renewables. Figure 13 shows the short-term price impacts for selected Latin American and Caribbean countries. Panel A shows countries with a higher use of fossil fuels and Panel B those with a mostly renewable electricity matrix. In Panel A countries, a consistent increase in electricity prices may be observed during episodes of natural gas price volatility; as mentioned earlier, this is related to the fact that when dependence on natural gas is high, the marginal plant is often a gas-fired one. Panel B countries tell a different story. In these countries, the marginal plant is less frequently one that operates with natural gas, which generally determines the price in periods of peak demand or low hydroelectric, solar, or wind production.

In electricity markets with a high share of renewable energies, short-term electricity prices can reach levels comparable to those in markets dominated by fossil fuels. This is the case in Brazil and Colombia, whose generation is mostly based on hydroelectric sources. Although most of the time these markets have maintained average prices below US$50 per MWh, prices have spiked during periods of water scarcity, usually caused by climatic phenomena such as El Niño or La Niña. The same is true in Uruguay. Despite its high dependence on renewable energy, the country has reported short-term prices sometimes higher than those of countries with a low integration of these sources.

The following subsections present some relevant factors and characteristics of the Latin American and Caribbean markets that help explain price variability. We discuss the impact on electricity prices in countries with a predominant

FIGURE 13. Short-term electricity prices in Latin America and the Caribbean, 2019-2022



Source: Prepared by the authors with data from market operators.
Note: The figure shows the average monthly marginal costs for each market. In Mexico, the local marginal prices (LMP) of the day-ahead market were used; in Argentina, the operated marginal cost; in Chile, the average real marginal cost of the main busbars; in Peru, the average marginal cost of the main busbars; in El Salvador, the average spot price; in Colombia, the weighted average price (WAP) of the *Bolsa Nacional*; in Brazil, the average power clearing price (PLD, *Preço de Liquidação de Diferenças*) of the four zones; in Uruguay, the monthly average of the marginal operating cost.

integration of fossil fuels in their electricity matrices. The effect of droughts in countries that rely heavily on hydropower generation is also explored. It considers the influence of renewable energy and the nature of nodal prices. We also discuss episodes of extreme price volatility, such as the one taking place in Mexico and Texas in February 2021.

5.3 Electricity prices in electricity matrices with a high dependence on fossil fuels

Although Latin America and the Caribbean has a very clean electricity matrix compared to other regions, some of its countries still have a strong dependence on fossil fuels, particularly natural gas. In economic terms, natural gas has consolidated its position not only because of its competitive prices, low investment costs, and improvements in the efficiency of combined cycle turbines, but also because of its strategic role in the energy transition, serving as a bridge between high-emission sources such as coal and clean renewable sources. Natural gas has also played a crucial role in stabilizing some electricity markets, providing the flexibility needed to integrate VREs such as wind and solar. In the medium term, natural gas-fired generation will remain essential to manage the intermittency of renewable energy in those countries that lack hydropower capable of providing flexibility, until storage technologies become economically viable and demand response programs are widely adopted.

In recent years, Argentina has been diversifying its electricity matrix to reduce its dependence on fossil fuels and mitigate its environmental impact.

As can be seen in Figure 14, thermal plants have historically dominated the country, accounting for 60% of the generation; however, significant investments have also been made in renewable energies. Wind energy, in particular, has gained traction, due to the favorable conditions in Patagonia and the Pampas region. **Along with this transition, however, thermal plants play an essential role in spot price stability in the Argentinian electricity market.** This dynamic is relevant because, in times of lower hydroelectric generation—due to seasonal factors or droughts—, thermal plants usually compensate for the energy deficit, which can generate price variations. It should be noted that this interrelation between hydroelectric and thermal generation is common in many electrical systems since natural fluctuations and market demands require a constant and reliable supply of energy.

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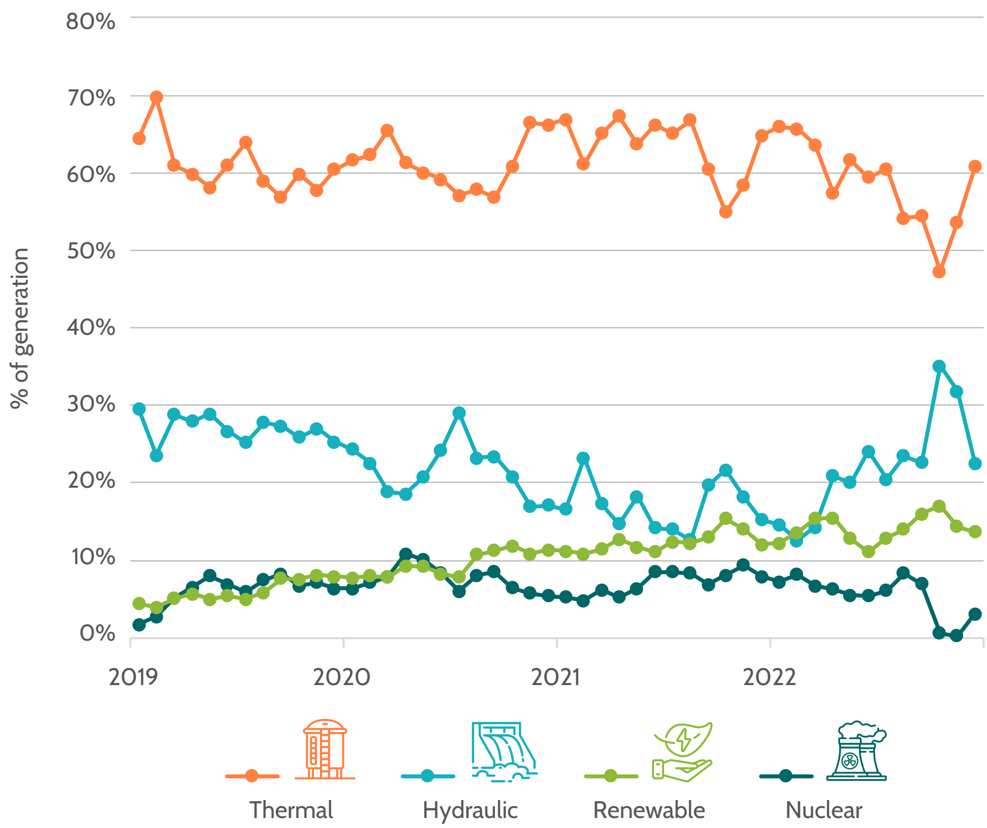
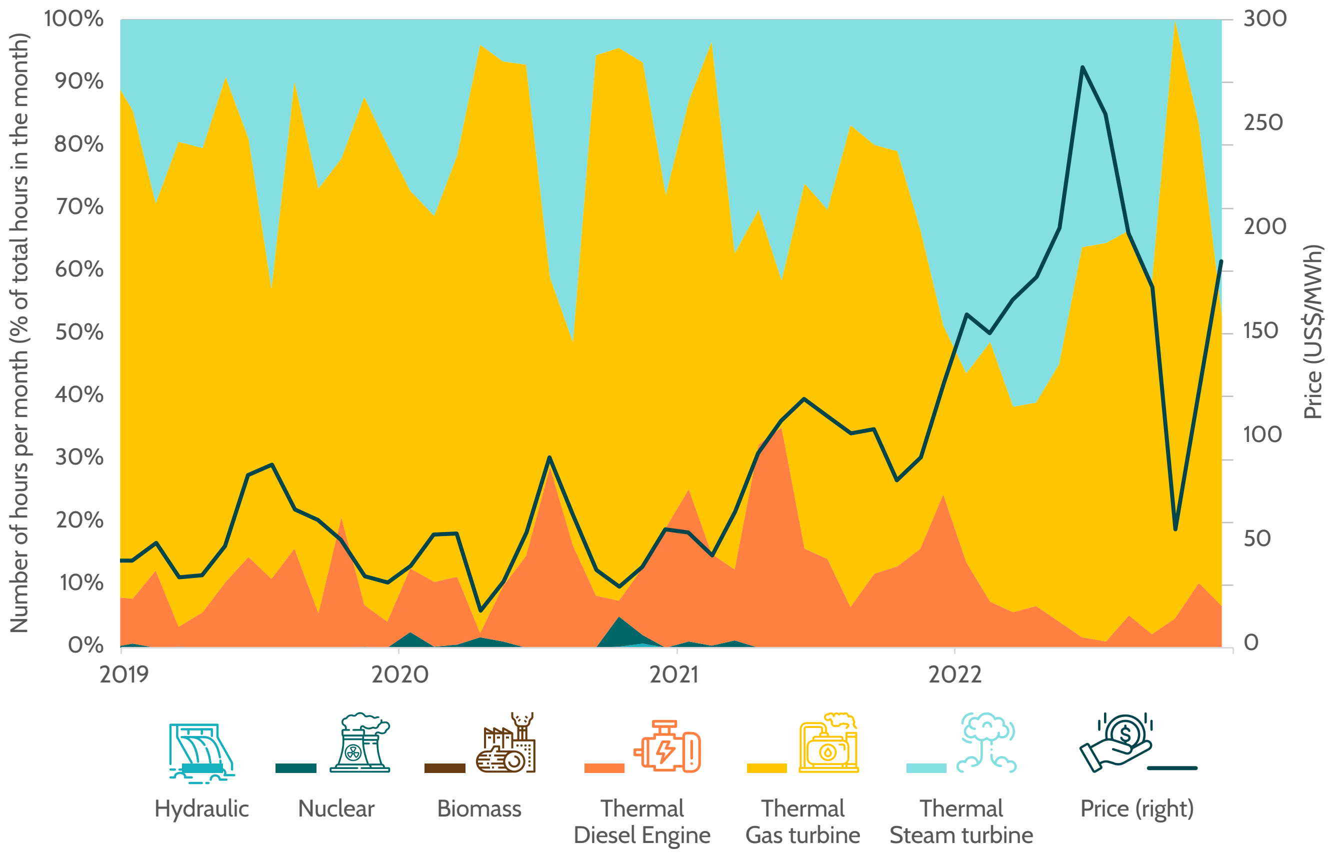
FIGURE 14. **Generation by source in Argentina, 2019-2022**



Source: Prepared by the authors based on data from *Compañía Administradora del Mercado Mayorista Eléctrico Sociedad Anónima* (CAMMESA).
Note: The graph represents the monthly percentage of electricity generation by source in Argentina's MEM. The "renewable energy" category encompasses wind, solar, biomass, biogas, and renewable hydroelectric power with a capacity ≤ 50 MW. It is evident that, although thermal generation dominates the market, the share of renewable energies is on the rise.

Figure 15 shows the percentage of hours in which each type of plant, according to its generation source, establishes the marginal price in the Argentine spot market. This means that it displays which plant acts as a reference for spot price determination at any given time. Thermal plants with turbo gas engines set the price for most of the hours, followed by turbo steam and diesel plants. This scenario highlights the vulnerability of the Argentinian electricity matrix to fluctuations in international fuel prices. Although the integration of renewable sources can help stabilize and potentially reduce spot market prices, the influence of fossil fuel prices will remain significant.

FIGURE 15. Number of operating hours by plant type and spot price. Argentina, 2019-2022



Source: Prepared by the authors based on data from CAMMESA.
Note: This chart shows the percentage of hours in which each type of plant, according to its generation source, establishes the monthly marginal cost in Argentina's *Mercado Eléctrico Mayorista* (MEM). Thermal plants are categorized according to the type of engine used. Turbo gas plants predominate in pricing, followed by turbo steam and diesel. The spot price is shown on the right axis. We can see that the marginal cost is usually influenced by the prices of fossil fuels, such as natural gas, as it follows the same trend as the index shown in Figure 9.

In Mexico, as in Argentina, natural gas plays a prominent role in the electricity generation matrix. These plants are essential to determine the short-term price of electricity. This relationship is clearly shown in Figure 16, which shows a marked relationship between natural gas and electricity prices. This dynamic is not limited to these countries. As shown in Chapter 4, European countries such as Germany and Italy have registered increases in their wholesale prices due to the influence of the price of natural gas in their electricity matrices.

Both Argentina and Mexico face similar challenges to those of European countries. This has raised the question of how to reduce the dependence of the wholesale price of electricity on fossil fuel costs. European countries have responded by substantially increasing renewable energies, hoping to decouple the price of electricity from the cost of natural gas in the future in order to achieve greater stability in wholesale prices.

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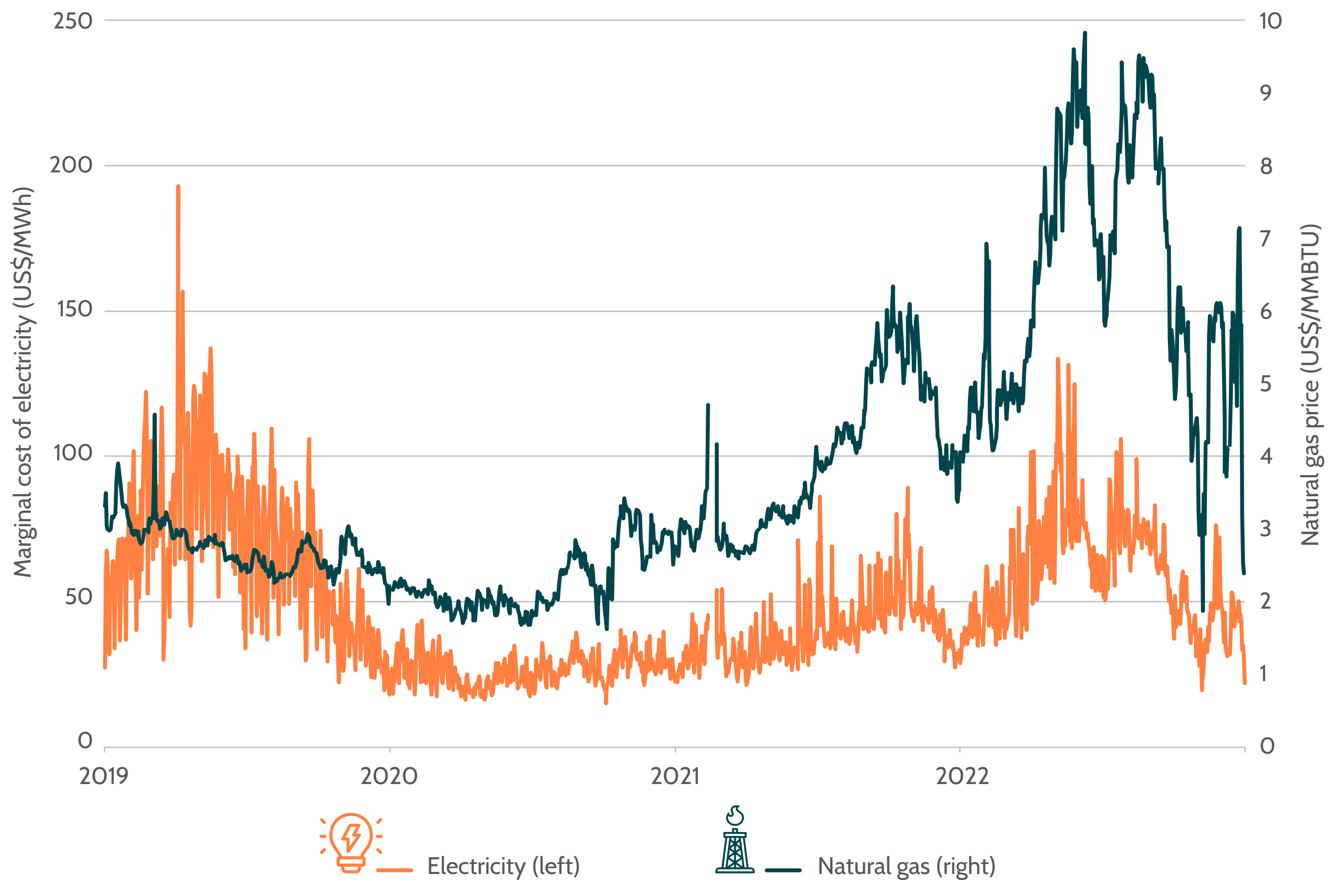
FIGURE 16. **Short-term price of electricity and gas in Mexico, 2019-2022**



Source: Prepared by the authors based on data from CENACE.
Note: The left axis reflects the average daily marginal cost of electricity in Mexico, while the right axis represents the price of natural gas, as reported by CENACE in its documents of total costs weighted by reference generation technology. The correlation between natural gas prices and electricity prices is evident. To more clearly visualize the relationship between the two variables, February 2021 prices have been omitted.

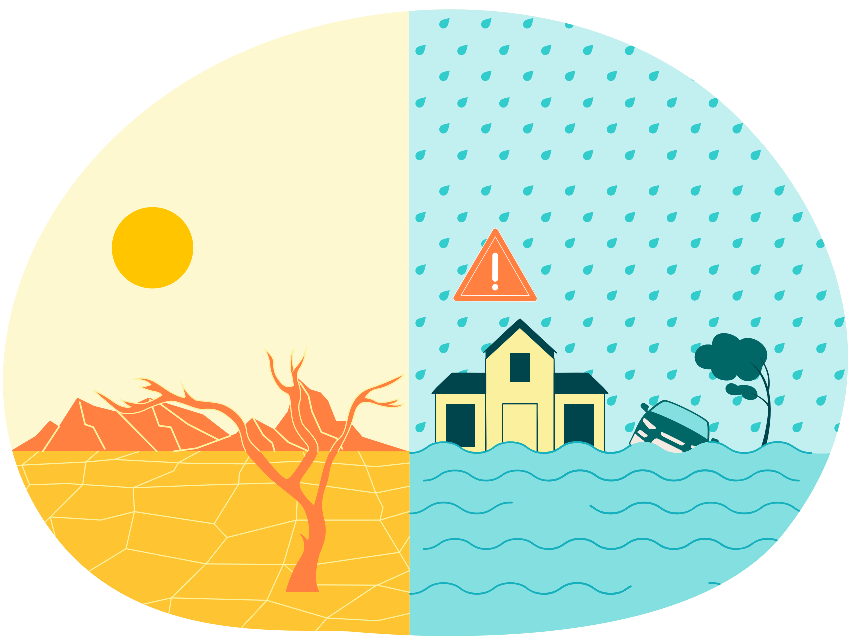
5.4 The influence of hydroelectric energy on market prices

Latin America and the Caribbean has a high percentage of renewable energy, mainly due to significant hydroelectric generation.

In countries with a strong dependence on water generation, the value of water is crucial in determining electricity prices. In other words, short-term electricity prices are tied to water cycles and water availability. Changes in precipitation patterns and extreme weather events, such as prolonged droughts, are the main challenges for the electricity sector in many countries of the region. These factors add complexity to the operational planning and management of the energy system.

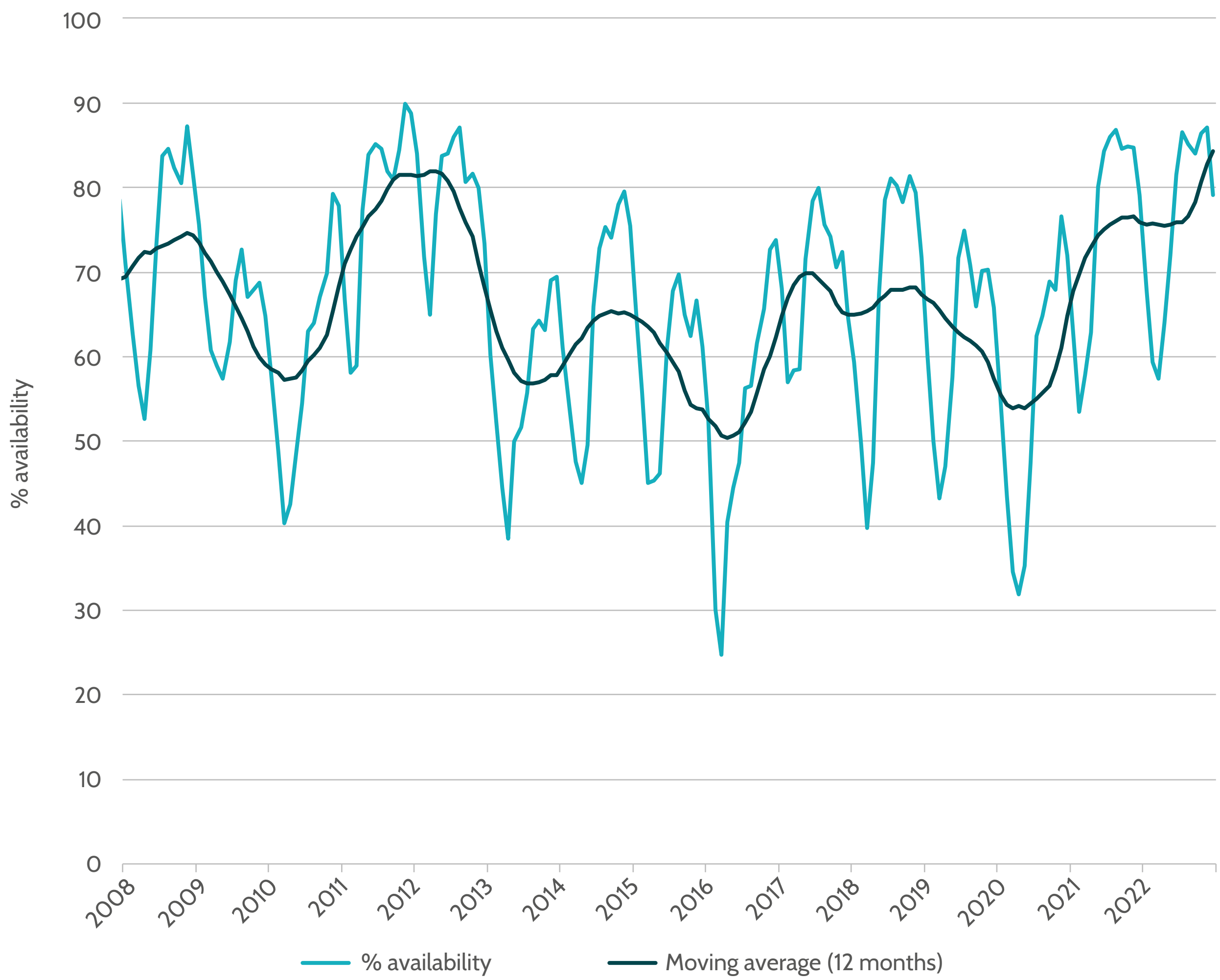
The Intergovernmental Panel on Climate Change (IPCC) states that Latin America and the Caribbean will experience even more variable and extreme conditions than at present, which could result in longer periods of drought and shorter and more intense rainfall events, as well as flooding (Castellanos *et al.*, 2022). The main droughts in the region have been linked to the El Niño Southern Oscillation (ENSO) phenomenon, which exacerbates these patterns.[28]

The Colombian electricity sector faces constant challenges; the risk of a deficit in hydroelectric power production and possible demand rationing during El Niño episodes are the most pressing. For example, during the last fifteen years, Colombia has experienced three notable El Niño episodes, in 2010, 2015, and late 2019. These episodes caused severe droughts in different regions of Central and South America. Figure 17 shows the accumulated reserves of Colombia's national interconnected system (SIN) and reveals a notable reduction in these periods. Droughts affect water levels in rivers that feed hydroelectric power plants, alter seasonal flows, and increase evaporation in reservoirs.



[28] The ENSO phenomenon has three phases: El Niño, La Niña, and a neutral phase. El Niño involves anomalous ocean warming in the central and eastern tropical Pacific, which decreases rainfall in Indonesia and increases rainfall in the tropical Pacific, weakening easterly winds. La Niña, on the other hand, is characterized by anomalous cooling in the same areas, with increased rainfall in Indonesia, a decrease in the central tropical Pacific and a strengthening of easterly winds.

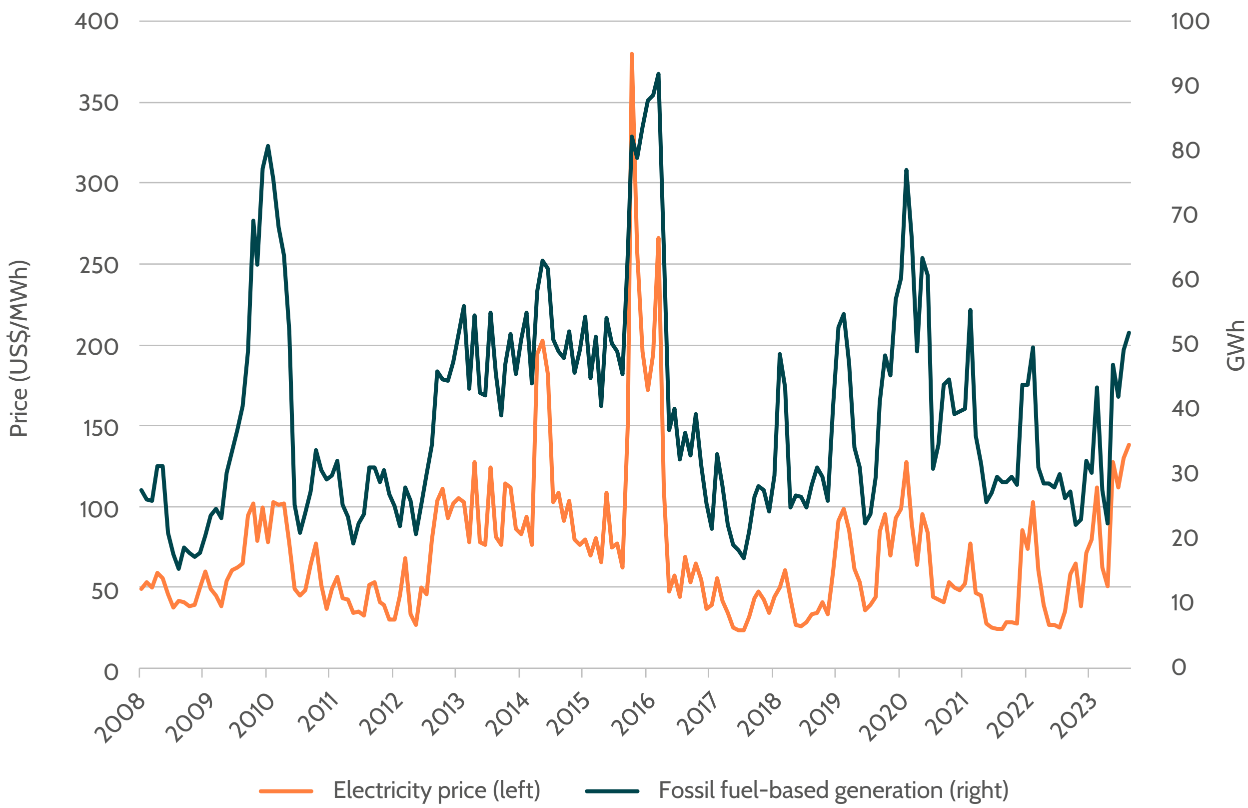
FIGURE 17. **Aggregate SIN reserves. Colombia, 2008-2022**



Source: Prepared by the authors based on XM data.
Note: The energy reserves of Colombia's national interconnected system (SIN) are based on the usable water stored in reservoirs to generate electricity. It is measured as the sum of the volume of all SIN reservoirs and is represented as a percentage of their total capacity. Reserves have fallen below 60% three times, affecting the country's power generation portfolio; the deficiency is compensated for with energy from thermal plants.

A direct consequence of El Niño for Colombia has been the need to increase the participation of thermal plants, albeit seasonally and generally not for very long periods. Figure 18 depicts the relationship between fossil fuel energy generation and the price of energy in the Colombian wholesale market. During periods of water stress, fossil-based generation increases significantly, and this increase is in turn closely linked to a rise in short-term electricity prices. This situation is aggravated by episodes where certain stakeholders exercise market power. In fact, the rise in prices during the 2015-2016 water stress period can be largely attributed to the increased ability of generating unit owners to exercise market power (McRae & Wolak 2017).

FIGURE 18. **Electricity generation and prices in Colombia, 2008-2023**



Source: Prepared by the authors based on Sinergox data.
Note: The figure shows the weighted average price (WAP) of the National Stock Exchange. This price corresponds to the highest offer price of the central dispatch units programmed to generate electricity at the ideal dispatch and which are free of inflexibility. The figure also shows the actual monthly generation of the National Interconnected System.

Within the Colombian auction market, spot prices are determined to a greater extent by emerging bids from hydroelectric plants than by established prices from thermal plants. Figure 19 illustrates the average behavior of bid prices as a function of generation technology and stock market price. To counteract these episodes of high prices, an upper limit, called the scarcity price, was established. The scarcity price acts as a regulatory mechanism; it avoids drastic price increases and sets a limit on electricity tariff increases.

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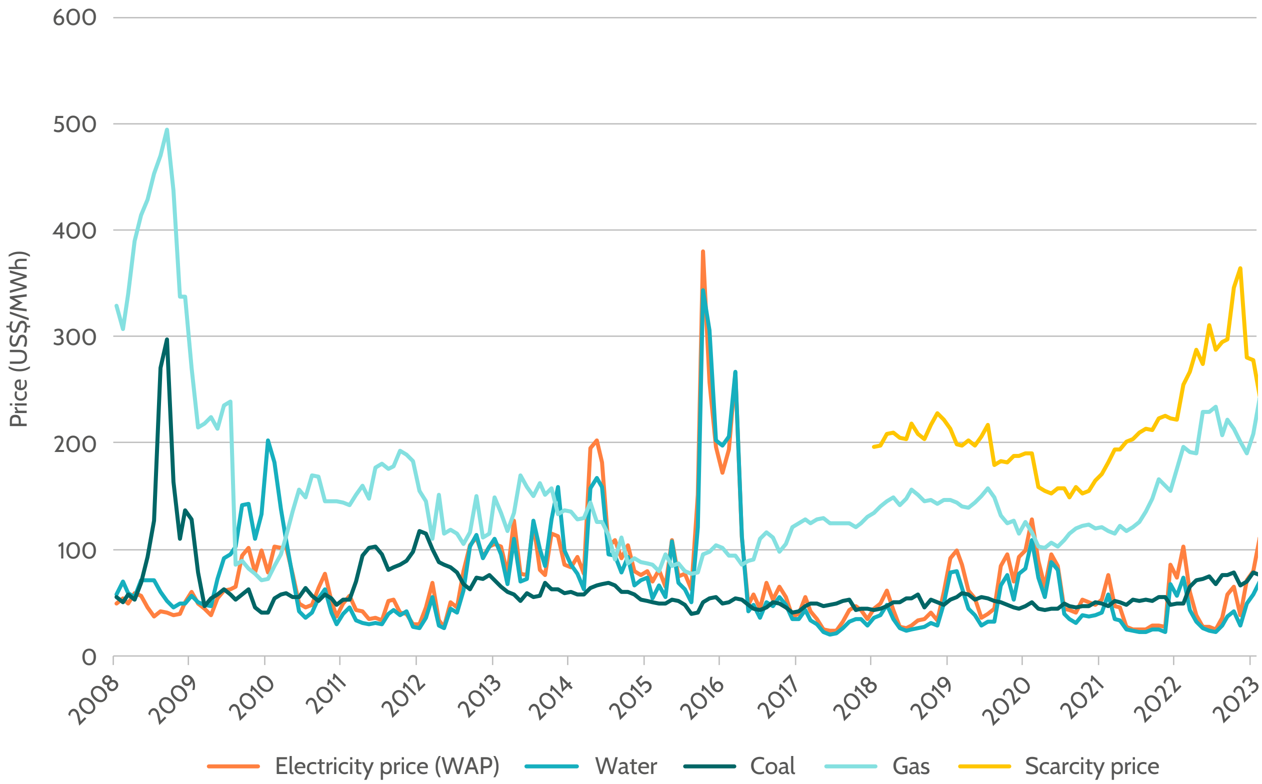
FIGURE 19. **Wholesale electricity prices in Colombia, 2008-2023**



Source: Prepared by the authors based on Sinergox.
Note: The figure shows the weighted average price (WAP) of the National Stock Exchange of electricity. This price corresponds to the highest offer price of the central dispatch units programmed to generate electricity at the ideal dispatch and which are free of inflexibility. It also shows the average price offers for MWh generated from hydroelectric plants, thermal plants, and the scarcity price. The scarcity price is the maximum value of electricity determined monthly according to regulations, and is based on variable costs of the National Interconnected System and the cost of fuel.

Like Colombia, Brazil has an electricity matrix dominated by hydroelectric generation

Electricity from hydropower has accounted for more than 70% of the total in the last two decades.

Although events affecting water availability impact wholesale electricity prices in both countries, they do not do so in the same way. Brazil stands out for managing its electricity market with a system based on audited costs, instead of the Colombian auction system.

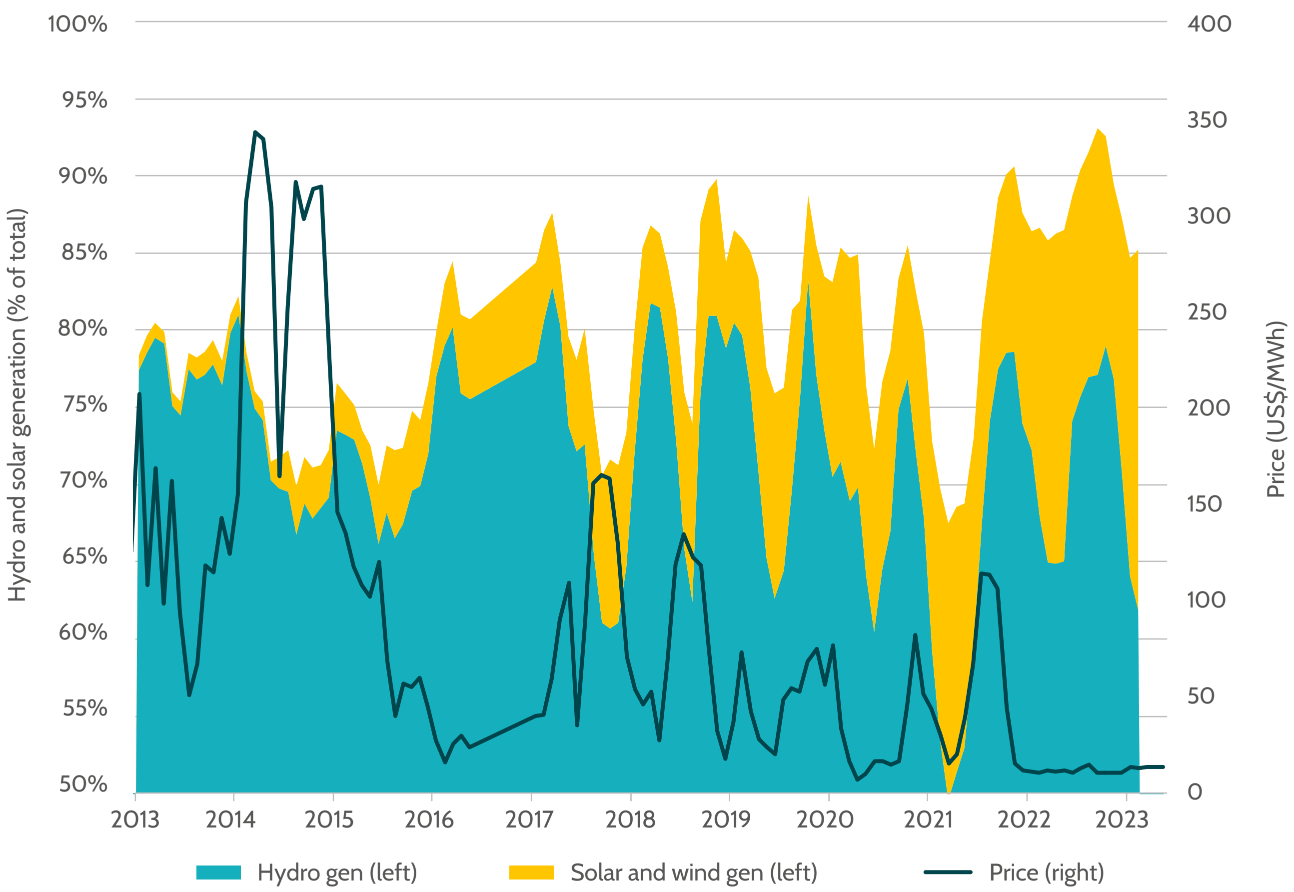
Due to the large size of the Brazilian electricity system and the hydrological variations between regions and seasons, hydroelectric power plants generate variable volumes of energy. To mitigate this risk, Brazil uses an energy reallocation mechanism in the short-term market that distributes the variability among all the country's hydroelectric plants, compensating for regional and seasonal differences. This system guarantees greater stability in the electricity supply, preventing fluctuations in a region from significantly affecting the market and therefore short-term prices.

In Brazil and other cost-based markets, it is essential for operators and regulators to determine the economic value of water. In Latin America and the Caribbean, this value is established through simulations that consider different hydrological scenarios. In drought situations, the value of water is similar to the cost of rationing electricity since the full demand cannot be met. With average water reserves, the value of water is related to the more efficient thermal plant, which makes up for the lack of hydroelectric generation. But in times of heavy rainfall, when reservoirs are overfilled, the value of water becomes nil (Barroso *et al.*, 2021). This can be seen in Figure 20, which shows how prices in Brazil's wholesale market rise when hydroelectric generation decreases.

The year 2014 exemplified this dynamic clearly. Severe water shortages pushed electricity prices to nearly US$300 per MWh. During that period, Brazil generated 590 TWh of electricity, marking a 3.6% increase compared to 2013. However, a 4.5% decline in hydroelectric production, driven by drought conditions, was compensated by substantial growth in thermoelectric generation. Notably, electricity production from oil increased by 43.4%, coal by 24.2%, and natural gas by 17.5% (EPE, 2015).

In recent years, Brazil has managed to reduce the dependence of its electricity market on water resources. The integration of solar and wind energy, which have marginal costs close to zero, has mitigated price increases caused by decreases in hydroelectric generation. Brazil also has an advantage in incorporating these renewable sources: its existing hydroelectric storage capacity, which not only allows for short-term management, but also favors the long-term balance of supply and demand for VRE (Schmidt, Cancella & Pereira, 2016).

FIGURE 20. **Electricity prices and generation in Brazil, 2008-2023**



Source: Prepared by the authors with data from *Câmara de Comercialização de Energia Elétrica* (CCEE).
Note: The graph shows the average power clearing price (PLD) in the Brazilian market zones and the monthly percentage of generation from renewable energies, broken down by type of source. When hydroelectric production decreases, prices tend to rise. Solar and wind energy have further reinforced hydroelectric production, increasing the proportion of renewable energies in the electricity matrix and thus contributing to lower prices in the spot market.

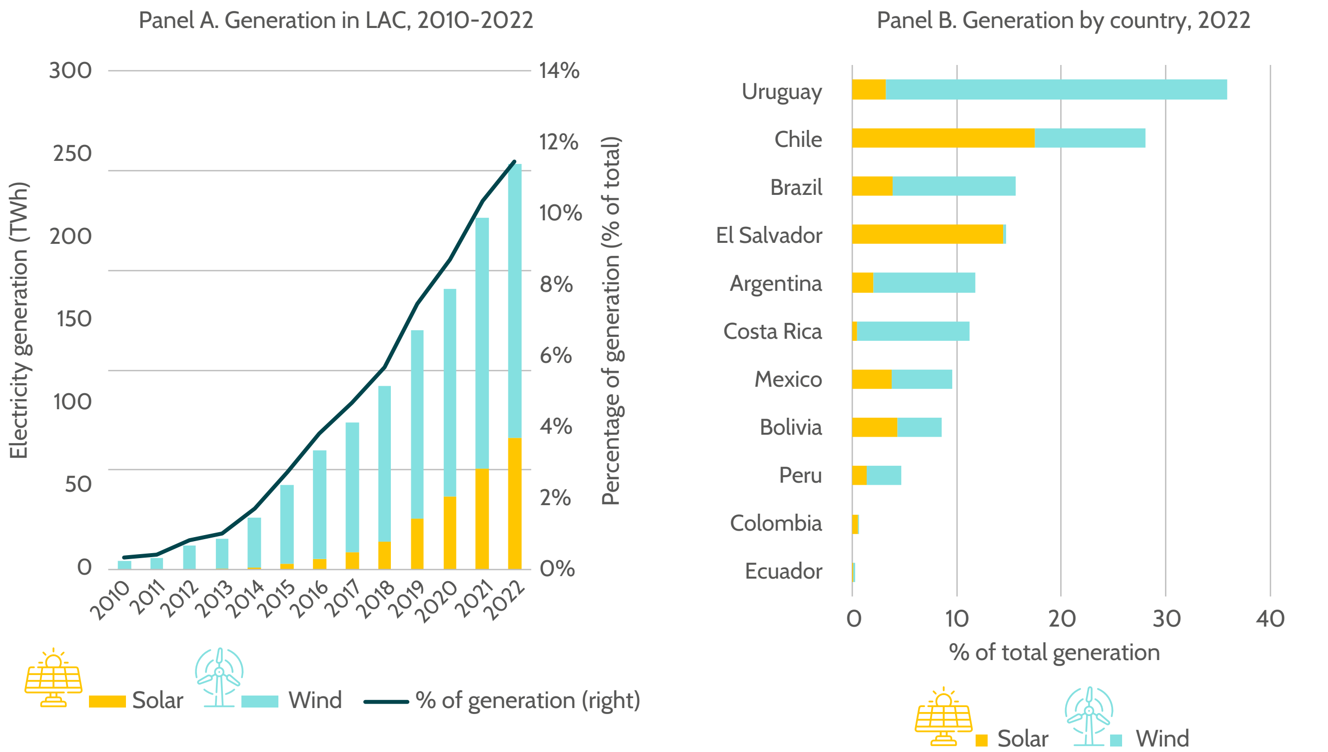
The impact of climatic phenomena on power systems becomes more critical when considering that, in the coming decades, certain areas of South America, such as much of Chile and parts of Argentina—from the central Andes to Patagonia—and Mexico will experience decreases in rainfall and pluvial flows (IEA, 2021a). These conditions may negatively impact the production of energy from hydroelectric sources. Both Argentina and Chile are likely to experience decreases in hydroelectric generation while, at the same time, the coastal regions of Andean countries such as Colombia, Ecuador, and Peru are likely to experience increased rainfall levels.

5.5 Price volatility in the context of increased solar and wind energy integration

The integration of solar and wind energy poses new challenges to the wholesale markets, as explained in chapter 3. The increasing importance of these energy sources over the last 10 years raises the question of whether current market designs can guarantee short and long-term electricity supply in the face of the inherent uncertainty in their generation and their near-zero marginal costs. Latin America and the Caribbean has witnessed a rapid integration of solar and wind energy over the last decade (see Figure 21). Compared to 4.6 TWh in 2010, in 2022 the region generated 230 TWh with these technologies, wind being the one with the highest integration. These technologies account for 12% of the generation in 2022. Its adoption in various countries has been mixed.

Countries such as Uruguay, Chile, and Brazil are at the forefront in the adoption of solar and wind technologies, as shown in Panel B of Figure 21. The adoption of these technologies has been influenced by regulatory frameworks, institutional structures, and the availability of resources, all aspects that these countries have been able to successfully leverage to promote solar and wind energy generation. Uruguay is leading these efforts in relative terms, with approximately 35% of its energy coming from these renewable sources, with wind power accounting for the largest percentage. Chile comes in second, generating 18% of its energy with these technologies, and then Brazil, with 15%.

FIGURE 21. Solar and wind power generation in LAC



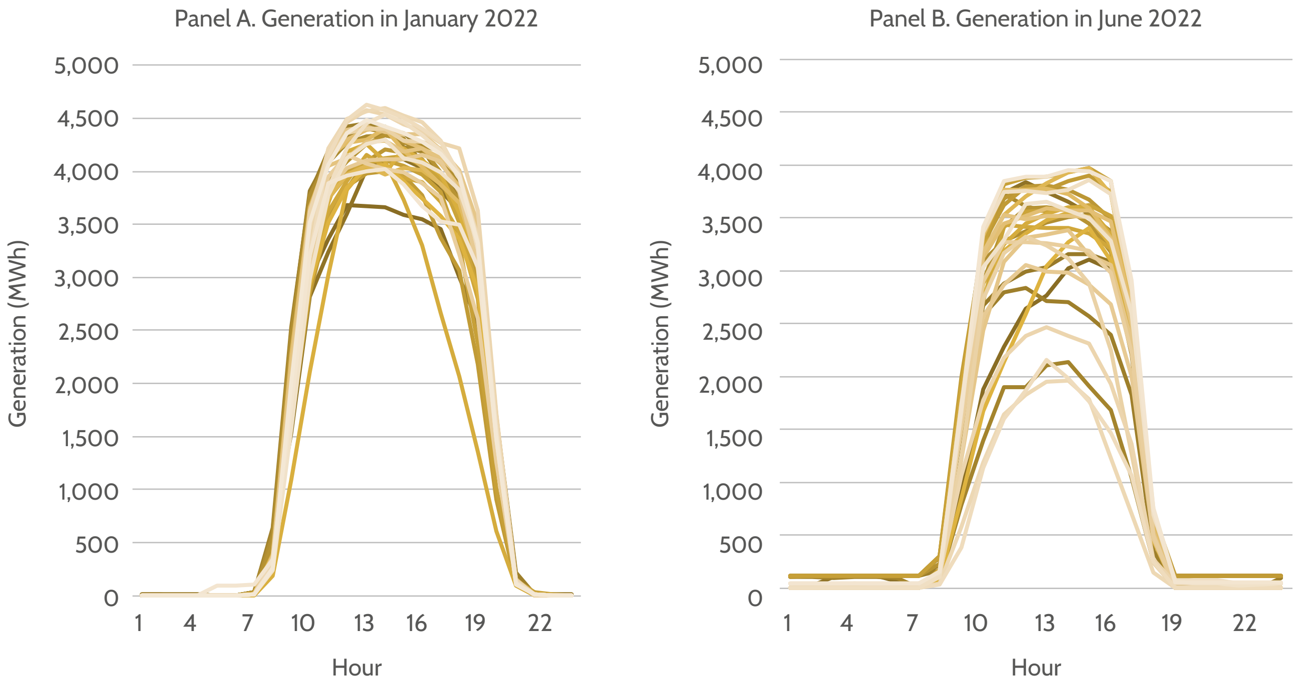
Source: Prepared by the authors with data from EMBER.
Note: The graph shows the annual evolution of solar and wind power generation in LAC. Solar production has increased considerably over the period analyzed, with a compound annual growth rate of 70%. Wind energy, on the other hand, has shown a growth rate of 30%. Thanks to the quick adoption and deployment of these technologies, by 2022 both sources accounted for about 12% of the total electricity generated in the region, as can be seen in the blue line in the graph in Panel A. Panel B shows the percentages of solar and wind power generation relative to total power for various countries in the region. Uruguay, Chile, and Brazil top the list in terms of the integration of these renewable energy sources, and Uruguay in particular stands out for its extensive deployment of wind power in relation to its total production. Chile is the country with the highest proportion of solar energy in relation to total energy.

Incorporating energy sources such as solar and wind entails the challenges inherent to their intermittent nature.

The ability to control the electrical output of these sources is limited; the load factor fluctuates with the season and time of day. In fact, a more detailed analysis of the operation of solar power systems can only be achieved by looking at their hourly production. Figure 22 shows the intermittency of solar generation in Chile, which varies between the hours of the day and between the days of the month.

Simple events such as a cloudy day can significantly affect the generating capacity of this technology. Panel A displays the hourly generation during January 2022. In this summer month, solar generation peaks between 13:00 and 16:00, although not consistently every day. Panel B shows solar generation in June, which is winter in the southern hemisphere: on certain days, production was only half of what was recorded during the summer days of January. This variability implies that, in the short term, the wholesale market should encourage the operation of plants, mainly thermal or hydroelectric plants, capable of providing the flexibility required by these fluctuations.

FIGURE 22. **Solar generation in Chile per hour, 2022**

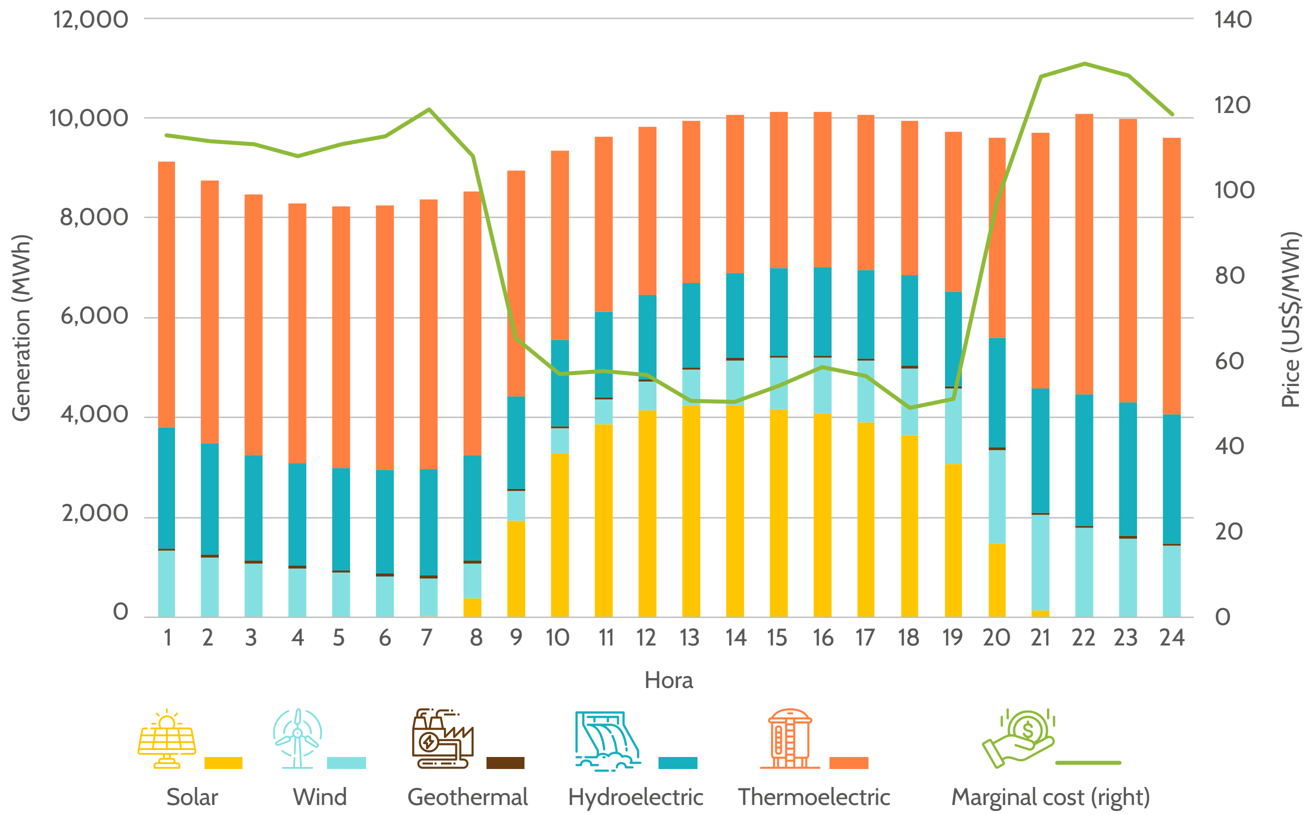


Source: Prepared by the authors with data from the National Electric Coordinator.
Note: Each panel in the figure displays the daily hourly solar generation within the Chilean National Electric System (SEN) for the respective month. Solar generation varies even between consecutive days of the same season. These fluctuations can be caused by various atmospheric conditions, such as clouds, which negatively impact the performance of the solar panels and decrease the plant factor. The figure also clearly highlights the inherent seasonality of solar generation. January, mid-summer in the southern hemisphere, shows higher energy generation compared to June, a winter month. This seasonal contrast underscores the dependence of solar energy on weather conditions and the relative position of the sun at different times of the year.

The effect on spot prices is clear: as more solar power generation is integrated, variability increases. Price behavior is generally divided into two periods. In the first, where solar generation is non-existent, the market equilibrium price reflects the marginal cost of thermal plants, which tend to have a higher cost. Second, when solar plants generate electricity, this marginal cost is reduced, as plants with lower costs are prioritized over those in a non-solar scenario.

Although the incorporation of solar energy leads to a decrease in average wholesale prices, the variability of these sources leads to significant price fluctuations throughout the day. Figure 23 presents the average hourly generation during January 2022 in the Chilean SEN. When solar plants fail to provide electricity, thermal power plants take their place.

FIGURE 23. **Generation and price of electricity per hour in the Chilean market, January 2022**

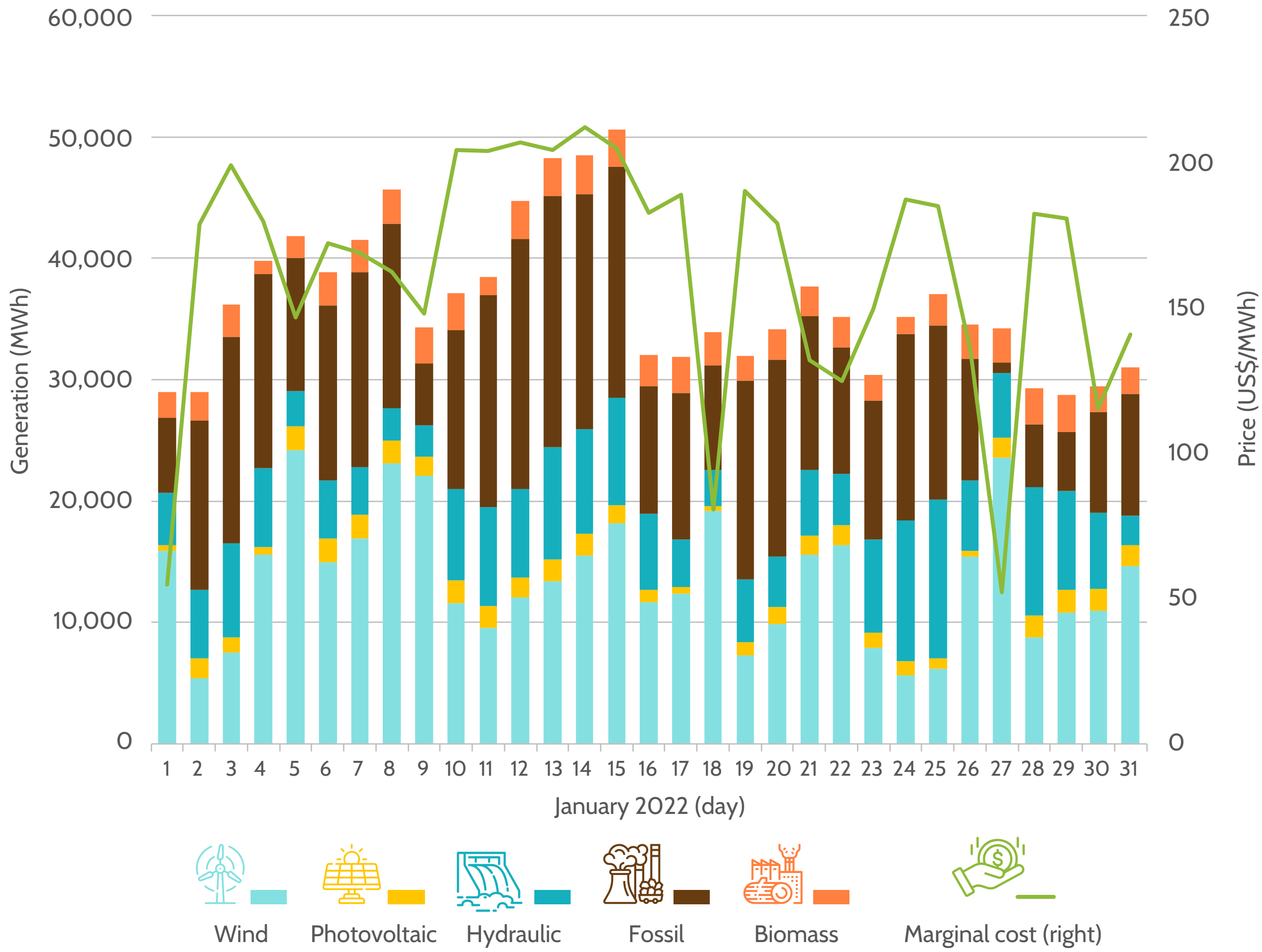


Source: Prepared by the authors with data from the National Electric Coordinator.
Note: The green line shows the January 2022 average monthly nodal hourly price in the Chilean SEN. This was estimated as the hourly average of the local marginal price. The bars show the average generation per hour according to technology in the National Interconnected System, which includes the main generation technologies. Marginal market electricity costs decrease as solar generation increases. These days were chosen for illustrative purposes only.

Like solar energy, wind energy production is also intermittent. Uruguay stands out as one of the leaders in the integration of wind energy in Latin America and the Caribbean and is therefore a good example. Figure 24 shows energy generation by type of technology during January 2022 in the Uruguayan electricity system. On days with a predominance of fossil fuel power generation, prices rise to values close to US$200 per MWh. Conversely, in periods with less dependence on these plants, prices tend to decrease.

Price variability seems to be determined by at least two factors. First, wind generation: on days with low wind production, prices increase. Second, electricity demand: on days with peak demand, a greater contribution from thermal generation is required, which also leads to higher prices. The Figure suggests that, despite Uruguay's commitment to renewable energy sources, marginal plants—which are often thermal—will continue to dictate prices.

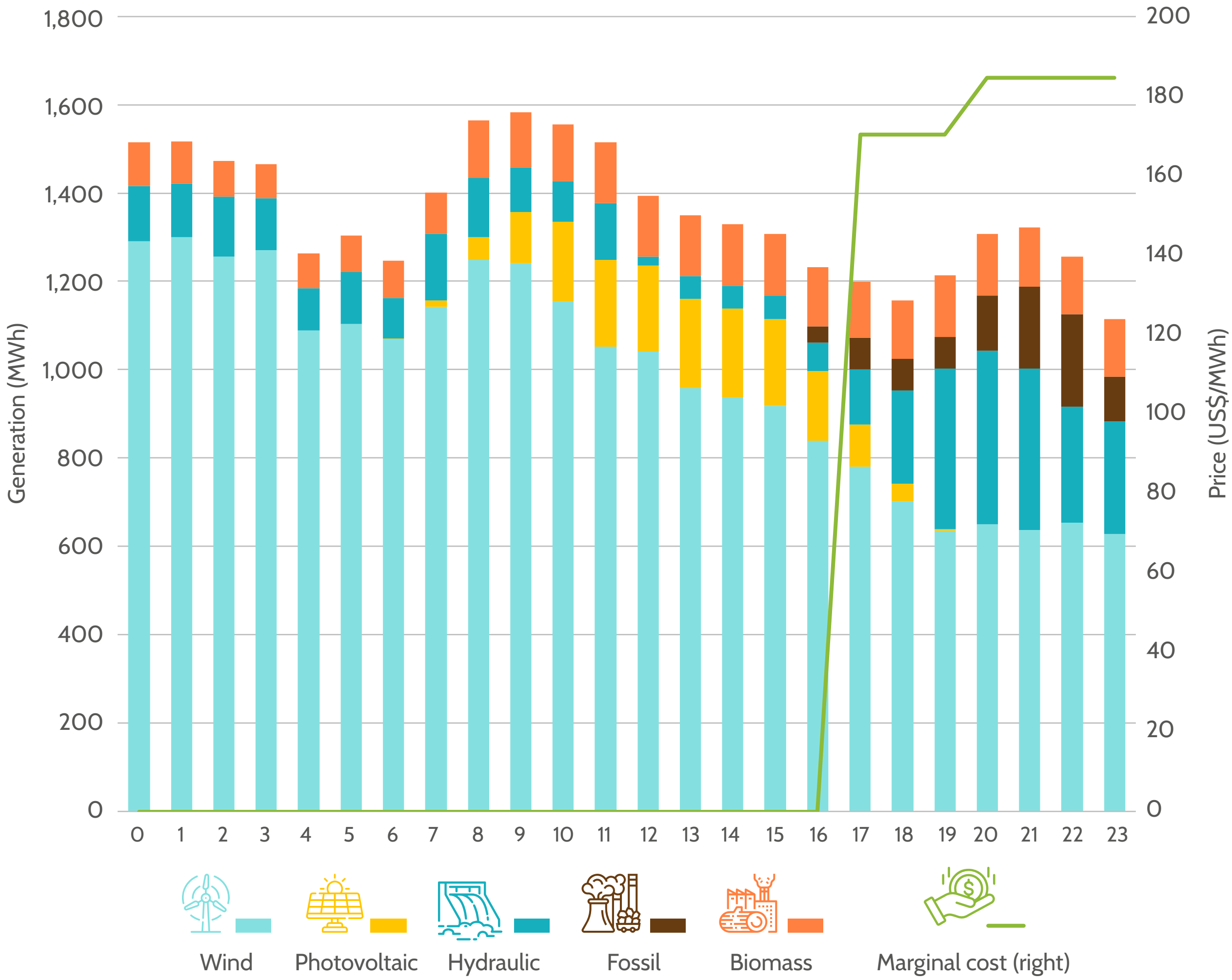
FIGURE 24. **Short-term electricity generation and price per hour in the Uruguayan market, 2022**



Source: Prepared by the authors with data from ADME.
Note: The green line shows the January 2022 daily average of the daily marginal cost of electricity. Short-term prices are those marketed in the *Despacho Nacional de Cargas* (DNC) of the *Administración del Mercado Eléctrico* (ADME) of Uruguay. The bars show generation per hour and per technology in the wholesale market. In periods with higher fossil fuel energy generation, prices tend to increase up to US$200 per MWh. In periods when these plants are less in demand, prices tend to be lower. At least two components could explain the price variability: first, wind generation, since on days with little wind generation prices tend to be higher; second, electricity demand: on days with more peak demand, more thermal generation is required and the price increases. The figure shows that although Uruguay has a high penetration of renewable energies, the marginal plant, which in many cases is thermal, will continue to determine prices.

In scenarios with strong wind power integration, is it possible to have periods where marginal costs approach zero? Figure 25 shows a day in which, for most of the day, prices effectively converged to zero, because of significant wind and solar generation and low electricity demand in the Uruguayan market.

FIGURE 25. Electricity generation and price in Uruguay, January 27, 2022



Source: Prepared by the authors with data from ADME.
Note: The green line indicates the daily marginal cost of electricity, with prices reflected in the *Despacho Nacional de Cargas of the Administración del Mercado Eléctrico* in Uruguay. The bars depict hourly electricity generation by technology on January 27, 2022. Most of the time, wind and solar energy make the marginal cost zero. At times of lower generation from these sources, thermal plants step in and determine the spot price in the market.

Markets with a high degree of integration of renewable sources highlight the need for flexibility in electricity markets and grids. Proper management of these challenges is central to prevent the premature retirement of power plants that, despite not operating constantly, are essential in situations of low wind or solar generation, as well as during peak demand, thereby ensuring reliability in the supply of electricity. In a context where zero marginal costs prevail, some plants would possibly be forced out of operation; in episodes of stress, power outages would be required to balance supply and demand, and all market participants would be affected. The situation raises questions about the current design of the wholesale market to ensure efficient operations and re-emphasizes the importance of adequate financial support, on the one hand, to retain existing generators that balance the system and, on the other hand, to encourage the incorporation of storage systems and new and flexible generators, in addition to investments in transmission systems.

5.6 Extreme weather events and power systems

The electric system is facing increasing pressure from climate change. Global warming, permanent changes in rainfall patterns, sea level rise, and extreme weather events currently pose a significant challenge to the resilience of electric systems and increase the likelihood of power outages. Climate change directly affects every segment of the electricity system, from generation to demand. In many countries, the increasing frequency and intensity of severe weather events—droughts, heat waves, cold waves, forest fires, cyclones, and floods, among others—have become the main cause of large-scale blackouts. Recent power outages in California due to extreme heat, in Texas due to cold snaps, and in Australia due to wildfires, highlight the current vulnerability of electric systems to these climatic hazards (IEA, 2021b). The importance of diversifying the electricity matrix to cope with this type of phenomena has been repeatedly confirmed.

In February 2021, Texas experienced a weather event that tested the robustness of its electrical infrastructure. Between the 14th and 18th of that month, the Lone Star State experienced extremely cold temperatures, snowstorms, and ice formations. The Electric Reliability Council of Texas (ERCOT), responsible for managing the power grid, faced unprecedented difficulties. By February 16, nearly one-third of its winter capacity was inoperative (King *et al.*, 2021). During the winter storm, several energy sources, including wind, reached a level of generation below expectations and the grid was destabilized. ERCOT, known for its high integration of wind energy, has flexible resources to counteract the intermittency of this type of energy in atypical situations. The scale of the event exceeded expectations. Outages in the natural gas supply chain played a crucial role in the failures of its generators. Insufficient electricity supply to meet demand led ERCOT to implement scheduled outages throughout the region to avoid a catastrophic system failure. Within the scope of ERCOT, 263 plants suffered outages, 95 of them total. There were many reasons behind these outages, but natural gas and wind sources accounted for a prominent share of the catastrophe, contributing about 41% of the unavailable capacity (Hartley, Medlock & Hung 2022).

Mexico, closely connected to Texas in terms of energy exchange, was not immune to the complications arising from the winter storm. Given its dependence on Texan natural gas, the Mexican electricity system faced serious challenges when the export of this essential resource from Texas became restricted. On February 13, Mexico's National Energy Control Center (CENACE) declared a state of alert in the national interconnected system and pointed directly to limitations in the supply of natural gas as the main cause of the situation. Gas and electricity prices rose to record levels across the country.

Figure 26, by comparing electricity prices in Texas and Mexico, provides a clear perspective of the differential impact on both markets. While both countries experienced price increases, the increase in Texas was enormous, up to forty times higher than in Mexico. Since ERCOT is an energy-only market with a maximum electricity price of US$9,000 per MWh, this event caused this limit to be reached in the short-term markets. These figures highlight the magnitude of the stress suffered by the Texan and Mexican systems. Certainly, it should be noted that the domino effect of the crisis was not limited to electricity alone but affected other sectors and aspects of the energy infrastructure.

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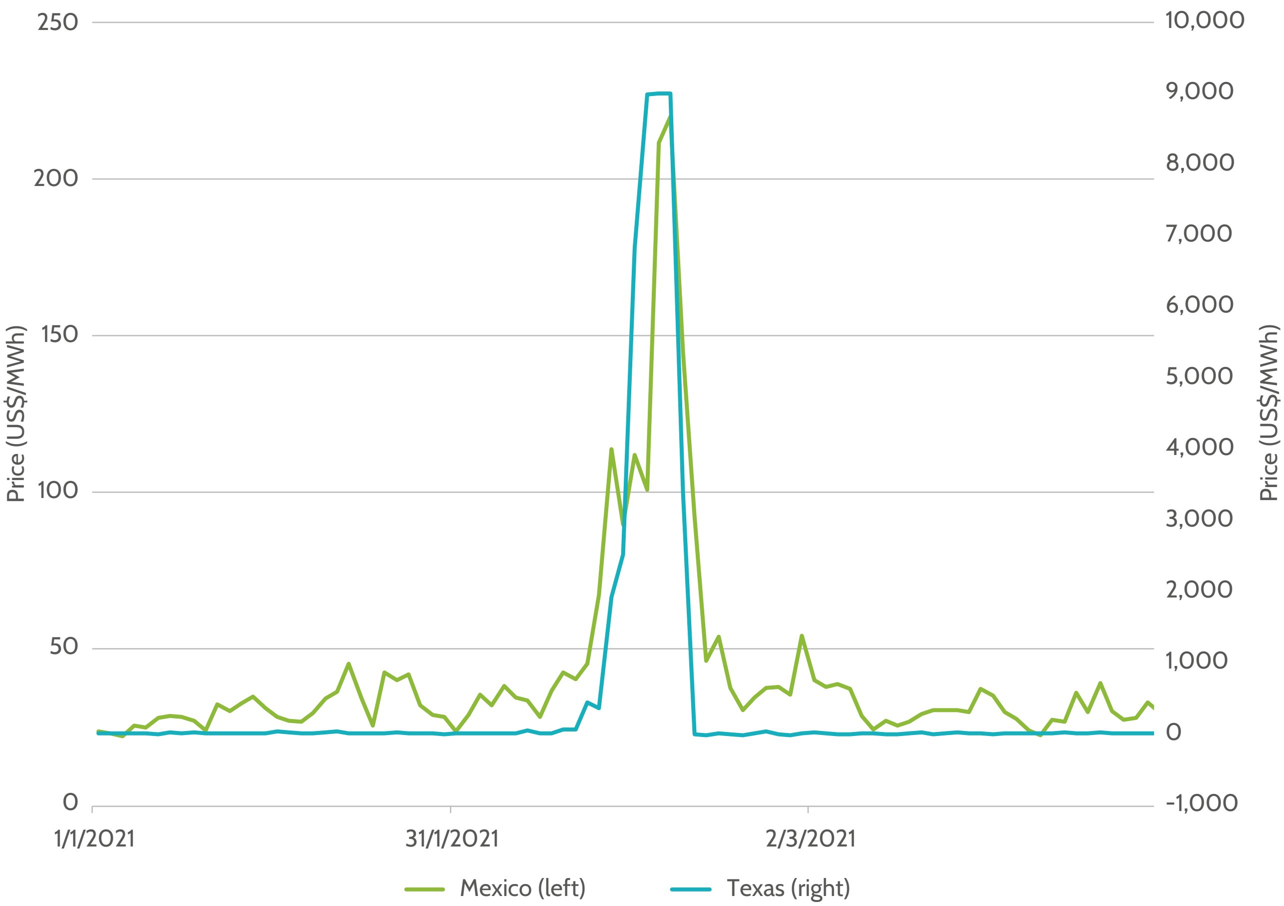
FIGURE 26. **Electricity prices in Mexico and Texas, 2021**



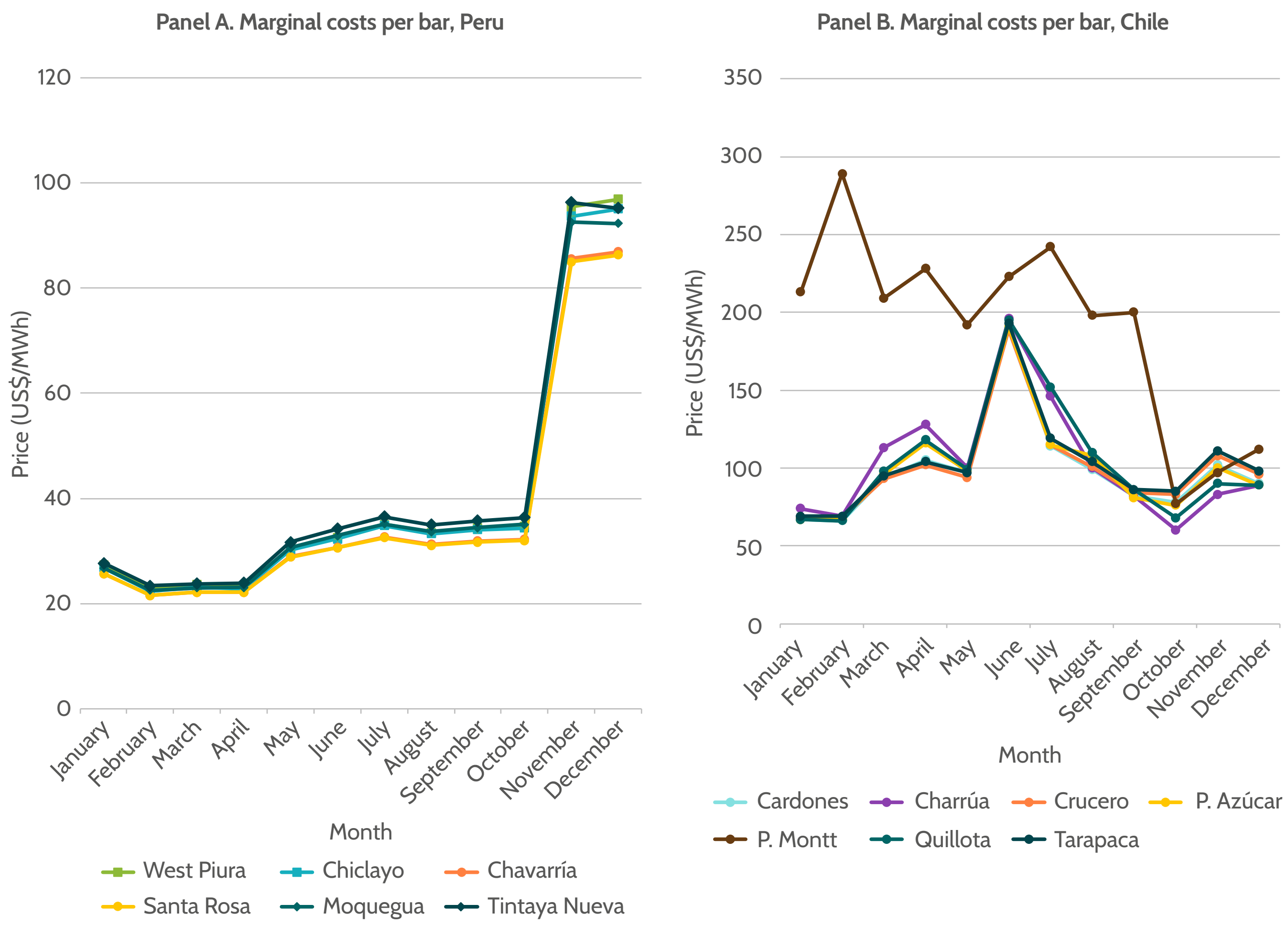
Source: Prepared by the authors with data from CENACE and ERCOT.
Note: The light green line shows Mexican DAM prices while the sky blue line shows Texas day-ahead prices. The figure shows the obvious effect on prices resulting from the extreme weather conditions in Texas.

5.7 Nodal and zonal price dynamics

The nodal pricing model, by design, is inherently more volatile than the zonal pricing model as it accounts for periods of transmission congestion and the associated energy losses. Nodal prices are particularly sensitive to the spatial variability of electricity demand, which can amplify price volatility. Countries such as Chile, Mexico, and Peru have adopted the nodal pricing model (see Table 6).

In the region, marginal price differentials between nodes are a mechanism to stimulate investment in electricity networks in areas with less infrastructure. Figure 27 shows the volatility between nodes within the Peruvian and Chilean wholesale markets. Panel A shows the monthly averages of the marginal costs of the main nodes of the Peruvian electricity market. The price contrast can be noted especially between the nodes located in the central areas (near Lima, the country's capital) and those in the extreme south and north of the country. The central nodes tend to reflect lower prices, an indication of the quality and capacity of the infrastructure in those areas and their proximity to power generation plants. According to the nodal market logic, high prices in areas with poor infrastructure should encourage investments to improve and expand the existing infrastructure. Panel B shows the marginal costs of the main nodes in Chile. As in the Peruvian case, differences in nodal costs account for congestion and associated electricity losses. At the Puerto Montt busbar, prices have exceeded those of other nodes, largely due to the replacement of conductors and the incorporation of the Tineo Substation Transmission System (Nueva Puerto Montt). **These examples underscore how important monitoring and understanding the structure and dynamics of nodal prices is, as they directly reflect the conditions and infrastructure challenges of electricity markets in the region.**

FIGURE 27. Nodal cost variation in Peru and Chile, 2022



Source: Prepared by the authors with data of the regulators.
Note: Both panels show the average monthly marginal costs recorded in the main busbars of each market. Panel A shows the case of Peru. Although there are periods in which price levels are similar, they tend to diverge in congested periods; the busbars in areas with greater congestion or losses are the ones with the most volatile prices. Some bars with smaller transportation networks, both in the north (Piura Oeste, Chiclayo) and the south (Moquegua, Tintaya Nueva) tend to reflect higher costs.

Unlike the zonal pricing model, the nodal pricing approach minimizes costly redispatches and promotes demand response in high-cost areas. This model optimizes grid capacity and generation efficiency through targeted price signals, encouraging investments in regions with significant price disparities (IRENA, 2019a). Over the long term, the price signals generated by nodal markets drive investments in both network infrastructure and generation capacity, fostering a more efficient and resilient electricity system.

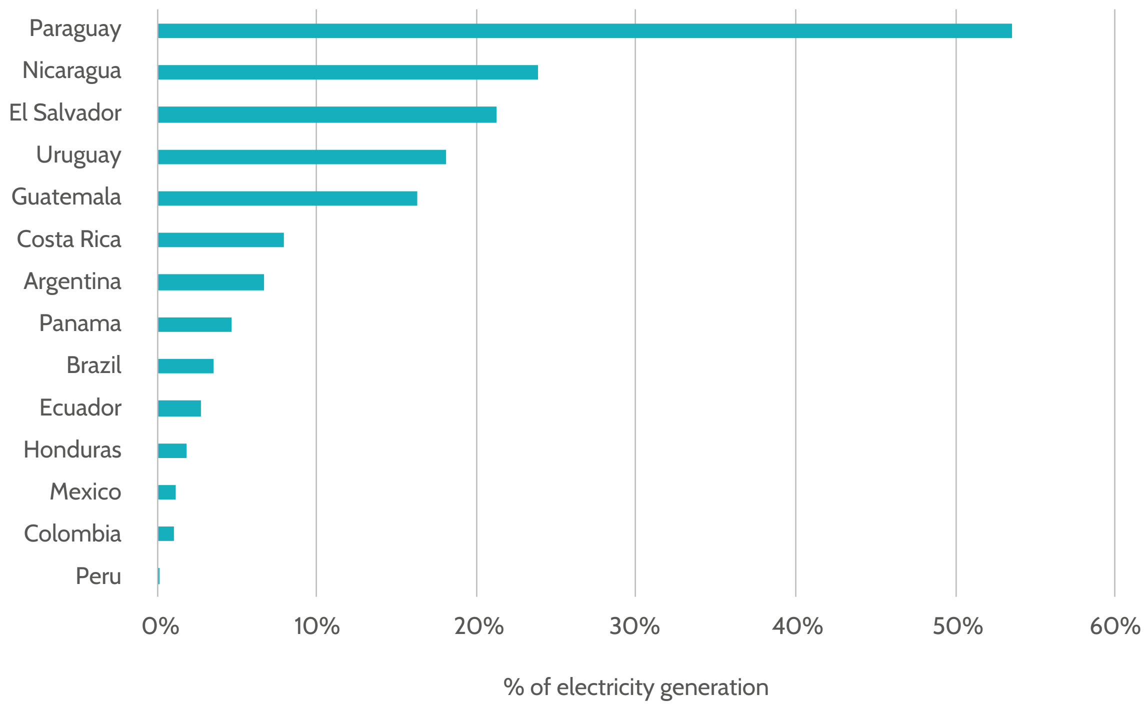
Certain exogenous factors, such as weather events or interruptions in the supply of essential inputs, may influence nodal prices uniformly, as was the case in Peru during November and December 2022. Hydroelectric generation experienced a significant decrease due to a delay in the rainy season because of the La Niña phenomenon. At the same time, natural gas plant generation also faced restrictions due to insufficient natural gas supply. The operation of certain thermal power plants was limited, according to reports from the Economic Operation Committee of the National Interconnected System (COES). These circumstances led to an increase in the short-term price of electricity, due to the incorporation of the cold reserve, based on coal and diesel, into the electricity system.

5.8 Regional integration

Electricity interconnection between some Latin American and Caribbean countries has contributed to achieving a reliable and secure electricity supply and has allowed for mutual support in the event of insufficient generation caused by high demand or unexpected generation outages (Levy, Tejeda & Di Chiara, 2020).

Figure 28 shows the regional electricity trade of the main economies in the region. Although the importance of electricity trade varies between countries, two groups with a high level of cross-border electricity trade can be identified: one in the Southern Cone and the other consisting of the Central American countries integrated in the SIEPAC system. In the Southern Cone, abundant water resources and bilateral connections encourage exports, as is the case in Uruguay and Paraguay. In the case of Paraguay, its energy profile is strongly linked to the large Itaipú and Yacyretá hydroelectric plants. Most of the electricity generated in these plants is exported to Brazil and Argentina, making electricity one of the country's main export products.

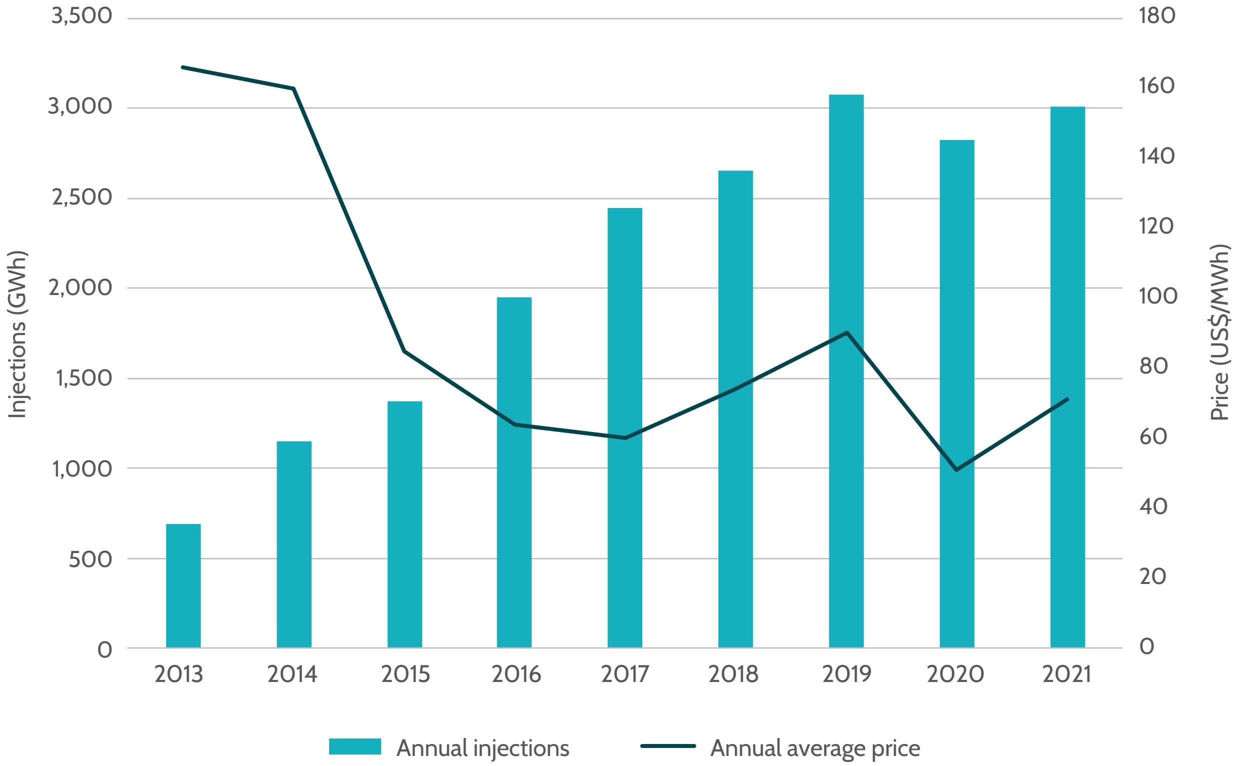
FIGURE 28. **Total electricity trade as a proportion of electricity generation in Latin America and the Caribbean, 2021**



Source: IEA (2024).
Note: Total trade refers to the sum of imports and exports.

The integration of Central American markets through the Central American Electrical Interconnection System has facilitated energy trade between member countries, increasing the energy traded by up to five times (see Figure 29). By enabling the exchange of energy between countries, vulnerability to extreme weather events or interruptions in local generation has been reduced. This increase has coincided with a reduction in electricity prices in the short term, driven mainly by the decrease in fossil fuel prices. Moreover, this integration has the potential to share renewable resources such as hydroelectric, solar, and wind power, allowing countries to purchase electricity at lower prices from countries with a high proportion of renewable sources.

FIGURE 29. **Transactions and price of electricity in the REM, 2013-2021**

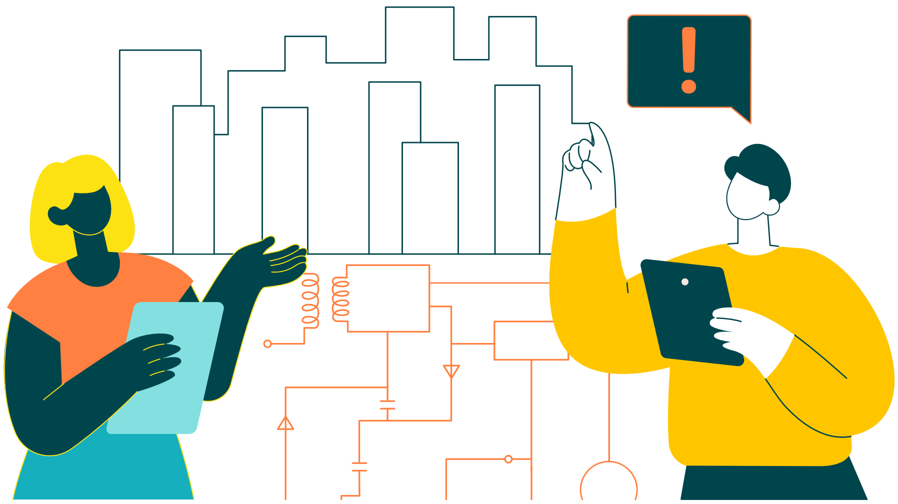


Source: Prepared by the authors with data from the EOR Annual Report 2021.
Note: The figure shows the electricity exchange since the entry into operation of the REM regulations and the Complementary Detail Procedure (CDP), to promote commercial transactions between agents in the region. Although most of the SIEPAC tranches were already operational, the regulation helped to harmonize the operation of their markets with the REM. On May 31, 2013, the Regional Operating Entity (ROE) carried out the first regional pre-dispatch in accordance with the REM regulations and the CDP.

In the context of renewable energy expansion, regional integration becomes increasingly important, enabling wholesale electricity markets to benefit from lower prices. In a recent study, Gonzáles *et al.* (2022) delved into the impact on renewable energy expansion of the interconnection between the two largest electricity markets in Chile: the *Sistema Interconectado Norte Grande* (SING) and the *Sistema Interconectado Central* (SIC). Their findings indicate that such interconnection has contributed significantly to the spatial convergence of nodal prices in the electricity market. In addition, the study highlights that this interconnection has facilitated the integration of renewable and low CO_2 emission power plants. As a result of this increased integration, marginal electricity costs have decreased significantly.

6

REFORMS TO THE LATIN AMERICAN AND CARIBBEAN ELECTRICITY MARKETS



6

REFORMS TO THE LATIN AMERICAN AND CARIBBEAN ELECTRICITY MARKETS

Short-term electricity markets in several Latin American and Caribbean countries often experience episodes of high short-term price volatility. These fluctuations can be primarily traced to two factors: the increase in fossil fuel prices and climate variability, which impacts water, solar, and wind resources. The situation is exacerbated by inefficiencies in wholesale markets, often related to limited competition and the lack of long-term markets. Although the region has shaped its electricity market based on its institutional and technological context, natural resources and specific needs, it cannot remain on the sidelines of the discussions that are currently underway in other latitudes. It is imperative that we rethink how to strengthen and make these markets more efficient in the face of increasingly volatile scenarios, and particularly in the face of the growing integration of variable renewable energies. Markets must guarantee security in the provision of services, allow for cost recovery, and provide incentives for investment in renewable energies to move forward in the energy transition.

In the following section, we address lessons that the region could draw from the discussions on electricity market reform. Without neglecting the challenge of adapting them to the specific conditions of each country, the measures being discussed in Europe should be incorporated into the range of options available to improve the efficiency of electricity markets in Latin America and the Caribbean. We have also summarized some proposals that seek to optimize the operation of wholesale markets for certain countries in the region, in order to improve their efficiency and mitigate the volatility associated with the growing integration of renewable energies.

6.1 Advancements in electricity market design in Latin America and the Caribbean

The electricity market designs of the United States and the European Union, although markedly different, offer important lessons for Latin America and the Caribbean. The main markets in the United States are distinguished by nodal markets and a centralized dispatch system, which also integrate a day-ahead market (DAM) with a real-time adjustment market (RTM). Europe, on the other hand, operates with zonal markets and a decentralized dispatch, complementing its DAMs with intraday markets (IDM). These differences highlight the different methodologies in the organization and management of electricity markets, offering a range of approaches from which practices applicable to the realities of Latin America and the Caribbean can be extracted.

Accurate price signals are at the core of efficient market designs and are key in both the short and long term. These signals are vital to encourage the efficient use of power system resources, ensure the continued availability of generators, promote the efficient use of energy, effectively manage grid congestion, influence consumption patterns, and promote investments in generation and transmission. Recent discussions on electricity market reforms in the European Union have highlighted the critical need for regulatory frameworks that facilitate the development of more efficient and resilient electricity markets, where prices accurately reflect real supply and demand dynamics.

Most liberalized electricity markets in Latin America and the Caribbean operate based on audited costs and centralized dispatches. These developing markets have a unique opportunity to benefit from the lessons learned in the United States and Europe. For policy makers in the region, implementing reforms in electricity market designs presents a path towards the evolution of energy systems that are better adapted to current and future needs. By taking advantage of international best practices, the region can steer its markets towards greater openness, competitiveness, and flexibility, thereby improving its ability to respond effectively to variations in supply and demand.

The design of short-term markets in Europe and the United States is based on a bidding system with remuneration based on marginal cost, a practice that has proven to promote efficiency in the operation of electricity markets. This model promotes flexibility, predictability, and effective integration of all technologies. In the region, the Colombian wholesale market and the Regional Electricity Market (REM) in Central America are the only bid-based markets, due to the reasons mentioned in the previous chapters. Some countries with more developed electricity markets, such as Brazil, Chile, and Peru, are analyzing the benefits of adopting this scheme, recognizing the need to adopt more open and competitive systems to facilitate the energy transition. One model that countries with cost-based markets could consider is the one adopted by Mexico, which introduces some flexibility in market bids.

Although there is a push towards bid-based electricity markets, it is crucial to recognize the risks associated with market concentration in a few hands within wholesale markets. This concentration can lead to price manipulation and higher prices, which is a concern for regulators and operators. As a result, several markets in Latin America and the Caribbean have adopted a structure based on audited costs to prevent such distortions. Furthermore, the large proportion of hydropower in the bidding market introduces unique challenges: producers are free to generate power when it is most economically beneficial to them, which could lead to a shift in power generation from times of high to low demand, thus manipulating market prices. This is an even greater problem when a single company controls a significant amount of hydropower production.

To ensure competition in bid-based electricity markets, particularly those with significant hydroelectric generation and shared flow systems, it is crucial to exercise meticulous oversight, implement mechanisms to ensure effective competition in generation, and establish well-defined property rights (Barroso *et al.*, 2021). Experiences in jurisdictions such as the United States have demonstrated the effectiveness of integrating limitations to market power directly into market management software, adapting dynamically to current conditions. It is therefore essential to adopt a proactive regulatory approach, including detailed data collection and market analysis, to ensure regulatory compliance and the timely identification and correction of any market design flaws. In addition, the implementation of efficient regulatory management, focused on the strategic planning of the transmission network, is essential to promote competition and market efficiency (Wolak, 2021b).

Spatial granularity is another element discussed. The European electricity market operates under a zonal design: supply and demand are grouped by pre-established zones. The United States has instead embraced a nodal system, which prioritizes economic efficiency by considering specific locations and transmission constraints. In 2023, the European Commission (EC) stated that a redefinition of the market with a more geographically focused approach would require significant changes to the current design. The committee is currently evaluating the pros and cons of transitioning to a nodal system. Migrating to a nodal system can reduce the costs associated with adjusting power generation to meet demand (redispatch), although this transition also introduces greater complexity into the system.

Adopting nodal pricing requires a detailed assessment of the specific conditions and degree of maturity of each electricity market. The potential benefits of moving to nodal markets include more efficient grid expansion planning, more effective control over market power, greater transparency in price formation processes, optimization of investment signals, improved incentives for investment in generation and transmission, potential for reduced energy costs in certain areas, identification of price anomalies, and more efficient market monitoring.

In Latin America and the Caribbean, the spatial granularity of prices adopted by markets is not uniform. Some countries have implemented nodal pricing systems, while others operate a single price scheme. Simplifying the structure of the electricity transmission grid can create advantages for market players seeking to increase their economic benefits, especially in countries where transmission infrastructure is limited. This may lead to an increase in electricity prices. Therefore, it is essential to analyze whether the shift to a nodal system would bring benefits to countries with a single price system, including the possibility of sending adequate signals for the development of electricity transmission. Although nodal markets offer the advantage of more accurately reflecting changes in supply, demand, and network conditions in prices, they can also be subject to the influence of market players seeking to manipulate outcomes. To mitigate these risks, it is essential to implement market power mitigation tools, active market surveillance, and sanction mechanisms for anti-competitive behavior.

Although the adoption of nodal pricing may lead to increased volatility in local prices, there are strategies to mitigate the impact on market participants, such as the use of financial instruments, including Financial Transmission Rights, or the bundling of nodal prices to protect consumers.

In Europe and the United States, the implementation of markets with multiple settlements and finer time granularity has been instrumental in improving price signaling, thus facilitating the effective integration of VREs and flexible technologies into the electricity mix. This adaptation is key to managing the variability of sources such as solar and wind, and emerging technologies such as storage. Conversely, wholesale markets in Latin America and the Caribbean still face significant challenges to fully adjust to the variable nature of renewable energies and to meet the demands of system flexibility.

Latin American and Caribbean markets must move from a single settlement model to a multiple settlement model, both financially binding[29] day-ahead markets (DAMs) and intraday (IDM) or real-time markets (RTMs). International experience shows that two markets improve the integration of variable renewable technologies into generation portfolios through more accurate price signaling and improved system flexibility. Likewise, the possibility of submitting bids minutes before electricity dispatch, instead of hours, would optimize the use of renewable energies and reduce the costs associated with imbalances.

A further improvement would be the joint optimization of the ancillary services and energy markets (DAMs), as is the case in some markets in the United States. This would allow system operators to contract some capacity to maintain balance during real-time operations, which would contribute to a more efficient allocation of generation resources.

Promoting a regulatory environment that encourages competition and establishes sanction mechanisms against anticompetitive practices would lead to more efficient short-term prices. This would include ensuring open access to the

[29] Refers to the existence of financial obligations associated with certain commitments or results; failure to meet these commitments may result in financial sanctions or penalties.

transmission network for all generators, separating transmission operations from generation and trading activities to prevent conflicts of interest, and fostering clear independence between market operators and regulators. Also, the implementation of measures to mitigate market power and effective surveillance systems.

Recent discussions in the European Union have highlighted the importance of reducing interventions or regulatory changes in wholesale markets in order to minimize increases in short-term electricity prices. In Latin America and the Caribbean, significant increases in marginal costs are often the result of high natural gas prices, shortages of hydroelectric generation, or short-term increases in demand. Therefore, it is essential to address these underlying causes in the medium and long term, which implies diversification of the energy generation portfolio and demand management policies, as has been proposed in Europe.

Diversification of the generation portfolio is crucial to mitigating periods of stress in the energy markets. The incorporation of renewable technologies such as hydroelectric, geothermal, solar, wind, and biofuels reduces dependence on natural gas and crude oil prices, thus contributing to a sustainable decrease in average electricity prices. This is particularly relevant for countries with a high dependence on fossil fuels. The expansion of solar and wind energy has shown that, although thermal plants may initially influence prices, the progressive integration of renewable sources leads to a reduction in average prices. Furthermore, in countries with significant hydropower generation and facing climate change challenges, it is essential to add alternative energy sources to mitigate the negative effects of droughts. This diversification strategy not only promotes sustainability and energy security, but also boosts economic stability by protecting consumers from extreme fluctuations in energy prices.

During episodes of volatility in the wholesale markets, when prices tend to increase, interventions should aim to protect the purchasing power of the most vulnerable households, be temporary in nature, and encourage energy efficiency, while preserving a stable regulatory framework that motivates investment.

Unforeseen regulatory changes can adversely impact the financial viability of energy investment projects, weakening investor confidence and raising the perception of risk, which, in turn, increases financing costs. This cost increase may hinder progress towards a cleaner economy, raising the costs associated with the energy transition.

The integration of electricity markets in the European Union (EU) has shown how the power sector can be made more resilient to adverse situations, particularly when a country's power generation is constrained. The ability to balance one country's electricity deficit with another country's surplus, taking advantage of comparative advantages, has proven to be an effective strategy in times of crisis, such as periods of drought that impact hydroelectric generation. This integration not only ensures a reliable and sustainable energy supply, but also contributes to lower electricity prices. This is achieved through harmonized regulations and the development of a robust cross-border infrastructure that facilitates these exchanges and promotes competition.

An illustrative case is France, which, as a traditional net exporter of electricity, has resorted to energy imports from neighboring countries to meet its domestic demand during the last energy crisis. These transactions have been facilitated through electricity markets, using marginal price signals and taking advantage of their integration model, which has avoided the need for complex political negotiations. Although markets in Latin America and the Caribbean are not fully integrated, cooperation between countries is essential to overcome the challenges posed by external factors that could affect the future availability of electricity in the region.

Table 7 presents a summary of the most significant changes proposed for short-term electricity market designs in Latin America and the Caribbean. Although these represent the main adjustments to be implemented, their application will depend on the level of development of the wholesale markets and will require a thorough analysis of the associated costs and benefits. In addition, the effectiveness of these changes will be enhanced by a sound institutional environment in which regulators and market operators not only promote transparency and economic efficiency, but also ensure market fairness and competition.

TABLE 7. Key recommendations for improving short-term electricity markets in Latin America and the Caribbean (1 of 2)

Current prevailing situation in the main liberalized markets in LAC	Possible regulatory improvements
Markets use marginalist remuneration.	Maintain the marginalist remuneration system since it has proven to be efficient in short-term markets. While lower average prices and higher volatility are expected due to the incorporation of variable renewable energy (VRE), these markets should maintain price signaling. In addition, given that marginal market costs will most often be 0 or close to zero, short-term markets must be complemented by secondary or long-term markets that allow for cost recovery and incentivize investment.
Most markets set prices based on audited costs.	The evolution towards bid-based markets allows for greater flexibility and competitiveness, with prices adjusting more adequately to actual demand and supply. Price bands around audited costs can help prevent anti-competitive practices.
Zonal markets predominate in the region.	The transition to nodal markets, where prices reflect local supply and demand conditions at specific points on the grid, can increase efficiency and encourage strategic investments in transmission and generation infrastructure. It also avoids the additional costs of re-dispatching processes.
The operation of most markets with a single settlement system means that transactions are settled at a single point in time, which may not adequately reflect market variations.	The adoption of multiple settlement systems, which allow transactions to be adjusted as more accurate information becomes available, improves efficiency and reduces costs in the market. This approach offers the flexibility to make corrections after DAMs, based on actual market behavior and variations in energy demand and supply. The DAM market should be financially binding.
Pricing on an hourly basis may not adequately capture real-time fluctuations in supply and demand.	Markets with finer time granularity, such as 15-minute intervals, can respond more effectively to variations, especially those related to solar and wind power generation.
The energy and ancillary services markets involve different optimization processes.	Co-optimization would maximize operational and economic efficiency by jointly considering the needs for energy and ancillary services, achieving a better balance between supply and demand.

TABLE 7. Key recommendations for improving short-term electricity markets in Latin America and the Caribbean Caribe (2 of 2)

Current prevailing situation in the main liberalized markets in LAC	Possible regulatory improvements
Price caps may be necessary to avoid excessively high prices during demand peaks, but if set incorrectly, they can distort the market.	It is essential to evaluate and adjust these caps carefully to ensure that they reflect market conditions and do not inhibit necessary investment, especially in markets where marginal costs are close to 0.
Market concentration can limit competition and efficiency.	Implement regulatory, economic policy, and oversight measures to encourage the entry of new participants and ensure a competitive environment.
Lack of incentives for flexibility may make the system less able to adapt to variations in supply and demand.	Implement incentive mechanisms, such as capacity payments and demand response programs, to stimulate investments in flexible technologies, energy storage, and distributed generation.
Excessive dependency on specific sources increases vulnerability to resource availability fluctuations or to international shocks in fossil fuel prices.	Diversify the electricity matrix with more renewable sources such as geothermal, solar, wind, and biofuels.
Intervene as little as possible in market designs during episodes of price volatility.	Interventions should prioritize efforts to maintain consumers' purchasing power rather than regulatory changes that could affect the usefulness of the projects.

Source: Prepared by the authors based on Barroso *et al.* (2021) and Ribeiro *et al.* (2023).

Complementarity with long-term markets

The short-term electricity market needs to be complemented by a long-term market. The latter should provide clear signals for long-term investments, more accurately reflect the average costs of different technologies, and offer protection against short-term price volatility (Ambec *et al.*, 2023 and Schittekatte & Batlle 2023b). Proper design of long-term contracts can optimize the functioning of short-term markets by reducing risks, containing potential abuses of power, and encouraging greater inclusion and participation. One of the best practices for consumer protection in the face of market price volatility has been the establishment of medium- and long-term contracts, which vary in duration (five, ten, and up to fifteen or twenty years) and according to the type of technology. Although there is an agreement to intensify long-term contracting, however, implementation is still under discussion. The main alternatives are private bilateral contracts, or PPAs (power purchase agreements), and contracts for differences (CFD) auctions, the former currently widely used in some Latin American and Caribbean markets. In markets with participants who face high fuel price risks, it is highly advisable to develop mechanisms to protect against fuel price volatility.

There are relevant opportunities to optimize the design of PPA markets. These markets face challenges in becoming more competitive, and often the agreed prices do not reach end consumers. The confidentiality of contracts, mainly negotiated bilaterally, reduces the transparency of these markets, which affects competition, generates entry barriers, and reduces the signals for future investments (Ambec *et al.*, 2023).

Certain adjustments can be made, however, such as promoting transparency in contract terms and prioritizing standardized auctions instead of individual negotiations (Ambec *et al.*, 2023). A substantial improvement in the operability of electricity markets is the transition from bilateral contracting systems to organized markets, as was the case in the U.S. PJM electricity market (Fabra, 2022, Mansur & White, 2012). The shift to an auction-based market system altered the strategies of market players, allowed for more effective information management and redirected production from high-cost plants to lower-cost ones. This restructuring led to a substantial improvement in market efficiency and proved that the benefits obtained more than justified the costs associated with the implementation of such a change.

In Latin America and the Caribbean, the use of long-term power purchase agreements (PPAs) purchased at auctions is common. These contracts are essential for investors, as they help to reduce dependence on short-term markets, which tend to have uncertain returns. This uncertainty is particularly relevant in markets with high integration of renewable energies, such as hydroelectric power, which has very low marginal costs. PPAs ensure constant prices, which reduces financial risks and favors long-term investments. Furthermore, the frequency of these auctions provides greater predictability to the market, making it more attractive for long-term strategic planning (Viscidi & Yépez, 2019).

Barroso *et al.* (2021) have suggested that Latin American and Caribbean countries should re-evaluate the duration of contracts and promote greater liquidity in long-term markets. Although long-term contracts are efficient for securing investments and minimizing companies' exposure to price volatility, they can also prevent consumers from benefiting from cost reductions resulting from technological advances and subject them to high prices compared to the spot market average. A clear example of how quickly energy costs can change is seen in the evolution of wind and solar energy (IRENA, 2023). In 2010, the levelized cost of electricity (LCOE) of onshore wind power was 95% higher than that of the cheapest fossil fuels. By 2022, however, this cost was already 52% lower than that of the cheapest fossil fuel-based solutions. Solar energy experienced an even more dramatic shift: in 2010 it cost 710% more than the cheapest fossil fuel option, and in 2022 it was 29% cheaper than that same option.

The high capital costs and long duration involved in power generation plants require reducing the level of uncertainty to the minimum possible, something that can be achieved through long-term contracts. These contracts, when overseen by regulators who determine the necessary investments, provide a stable framework for investment recovery and profitability (Ambec *et al.*, 2023, Fabra 2022). These contracts reduce investment risks, make it easier to obtain capital at lower costs, and increase competition. Furthermore, the structure of these contracts must be adapted to the different technologies and their ability to respond to short-term price changes.

For example, hydropower offers the advantage—key to the integration of VREs—of storage capacity. But there are also concerns about the abuse of market power and price manipulation. One type of contract specific to this type of technology is the so-called flexibility contract (Fabra, 2022). These contracts allow generators to sell their energy at the market price, and then receive the difference between a reference price and the average market price over an extended period of time. This ensures that plant owners maintain full exposure to the market price. The model also reduces incentives for hydropower plant operators to manipulate prices, thanks to long-term contracts with fixed prices.

Annex A **of this paper shows that there is common ground between the problem of generation expansion, the operation of marginal markets, and the hourly rates for end-user supply.** The concept of levelized, or total, costs is also explained, and it is argued that using them in an implementation of the pay-as-bid model in the dispatch algorithm can lead to unnecessary cost overruns.

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6.2 Improving the performance of electricity markets as intermittent renewable energies become more integrated

The discussion surrounding the reform of wholesale electricity markets, reignited by the recent volatility in short-term electricity markets, is far from new. The conversation has been going on for years, largely driven by the increasing integration of VREs, which changes the dynamics of wholesale electricity markets. These markets serve two functions: they determine dispatch by order of merit—taking into account safety constraints to ensure short-term reliability—and they establish the financial incentives and eligibility rules for investments—which ensure long-term reliability (Cochran *et al.*, 2013).

The structural conceptualization of electricity markets based on marginal cost, generation dispatch, and nodal pricing took place in a context of reforms during the 1990s and early 2000s (Joscow, 2019). In recent years, however, the integration of renewable sources, specifically solar and wind, has presented unprecedented challenges. Its intrinsic intermittency, coupled with its near-zero marginal costs, challenges the status quo of traditional electricity markets.[30]

Silva-Rodriguez *et al.* (2022) have identified the main challenges facing short-term wholesale electricity markets:

- **Prices close to zero:** as detailed in section 5.5, as VREs gain ground, prices tend to approach zero in certain periods. In this context, periods of scarcity, due to demand peaks or supply constraints, become critical to ensuring cost recovery and supporting new investments, especially in markets where the short term is more relevanta.

- **Externalities in price formation:** an efficient mechanism is needed to internalize both negative externalities (e.g. CO_2 emissions) and positive externalities (e.g. clean energy generation). Otherwise, wholesale prices may not reflect the true cost and value of the energy produced.

- **Promotion of competition:** the energy reforms of the last decades sought to promote competition. It is still necessary, however, to delve deeper into mechanisms to promote it within wholesale markets. A more competitively priced electricity sector must be ensured.

- **Incorporation of new players:** emerging technologies and decentralized forms of generation were not considered in the first wholesale market designs. To increase competition, these markets need to be modernized so that they become more flexible and open to the participation of new players. Likewise, the electrical infrastructure must be upgraded to integrate these new participants effectively. Similarly, the electrical infrastructure must be upgraded to effectively accommodate these new participants. Additionally, with the rise in variable energy generation, there may be a growing need for increased operating reserves.

- **Grid constraints:** low investment in electricity grids is a constant in Latin America and the Caribbean, so the infrastructure may not be sufficient to cope with the increase in electricity demand. Failure to consider transmission and distribution constraints can lead to sub-optimal investments and additional costs. As renewable sources increase, challenges related to grid congestion are likely to increase. Models such as nodal pricing can be a solution to incentivize strategic investments in infrastructure.

[30] Joscow (2019) argues that prices in the U.S. electricity market in a context of increased solar and wind integration and imperfections in wholesale markets may not be providing adequate signals to maintain efficient operations and incentivize long-term investments. Nor would they be encouraging the creation of new plants that provide flexibility and storage, or the maintenance of existing plants that are essential to the balance of the electricity system. These challenges are amplified by the presence of price ceilings and the inherent low elasticity of demand.

An additional challenge in the transition to renewable energies is the public perception that the low short-term average electricity prices generated by these sources do not necessarily translate into lower electricity tariffs. Yet this expectation does not consider other costs involved in the electricity system. Although energy costs are a relevant component of the electricity tariff, other significant costs include electricity transmission and distribution, electricity losses, reliability costs to maintain stable voltage and frequency, asset depreciation, marketing costs and taxes. It is therefore crucial to communicate clearly how electricity prices derive from multiple elements, not just the cost of generation. Understanding these dynamics is essential to aligning expectations with reality and fostering a more informed and sustainable energy transition to renewables.

Current wholesale energy market models may not fully adjust to the new reality arising from the integration of energy sources with marginal costs close to zero or even negative, as is the case of VREs (Schmalensee, 2019; Joskow, 2019). The growing participation of solar and wind energy would allow these sources to dispatch constantly during their generation periods. In contrast, traditional plants may find themselves operating in negative marginal cost contexts, avoiding the costs associated with plant start-up and shutdown. It is worth pointing out that in Latin American and Caribbean countries, the extensive integration of hydropower has resulted in short-term market prices close to zero for several decades. Nevertheless, it is important to understand the fundamental differences between hydropower and other renewable sources such as solar and wind. Hydroelectric power is characterized by its storage capacity and generation variability that does not occur in short periods. In contrast, solar and wind energy are inherently intermittent and do not have an inherent storage mechanism, leading to different challenges in terms of management and integration into electricity markets.

As renewable energy integration grows, wholesale markets must be able to generate incentives for plant capacity expansions that are simultaneously efficient and flexible.

Certain mechanisms that increase the flexibility of the electricity system, such as batteries and demand response programs, should be similarly incentivized. Another technology that can provide the desired flexibility is pumped storage.[31] The most efficient mechanisms to encourage the development of generation projects are the capacity, ancillary services, and contract markets (Schmalensee, 2019; Joskow, 2019). Although capacity mechanisms emerged as a tool to ensure generation reliability in future demand peaks, they were designed in markets with a predominance of thermal generation. However, in markets dominated by hydroelectricity or intermittent renewable sources—such as wind and solar—the dynamics change: the main risk to reliability is not so much the installed capacity but the actual availability of energy. That is, there may be times when, due to natural factors, there is not enough water, wind, or solar radiation to generate the necessary electricity.

One of the most promising mechanisms to lessen the effects of solar and wind energy intermittency in wholesale markets is energy storage. Energy can be stored when renewable generation is at its peak and sold when prices are high. This will also help to reduce both volatility and price levels in the short-term markets, at times when these technologies see their generation capacity reduced or there are demand peaks. It is therefore essential for regulatory frameworks to encourage the deployment and integration of storage systems in electricity markets.

Active demand-side management is becoming a key element in the energy sector. Many consumers nowadays do not see changes in electricity prices in the short term, which minimizes their active role in consumption. But with the increasing penetration of smart meters, tariffs can be adjusted in real time. When demand is high, prices may rise and encourage people to consume less. This is especially important as more sectors, such as transportation or heating, become electrified. These price adjustments can help balance and stabilize price volatility in the electricity markets.

[31] In LAC, although this technology is well known, its application is nonexistent compared to other regions (Ubierna & Alarcon Rodriguez, 2022).

The increasing price volatility in electricity markets, caused by a greater integration of solar and wind energy, gives a more relevant role to the ancillary services and long-term markets.

To guarantee adequate investment in generation and ensure that future demand and the remuneration received by plants in periods of scarcity are covered, capacity markets may be required. The high spot market prices resulting from high demand and insufficient supply allow for investments in generation in energy-only markets, where there are no capacity markets. Regulators in these markets, however, generally allocate maximum prices. If the caps are too low, they can complicate the operation of electricity markets that rely only on short-term prices to drive their expansion. It is imperative to adjust price caps to ensure cost recovery for power plants, especially in countries with rapidly growing demand or reduced generating capacity. The challenge becomes more acute with the massive incorporation of VREs. There is a so-called "cannibalization effect of renewables" because renewable energies are given dispatch priority. As the installed capacity of energies such as solar or wind power increases and fossil fuel-based generation decreases, renewable sources play a greater role in determining wholesale prices. For example, as more solar energy is integrated, more competition is generated among solar producers. This could lead to lower electricity prices, negatively impact the profits of renewable energy producers, and discourage investment in renewable energy (Fabra, 2022).

Furthermore, market designs must be adapted to encourage operational and investment flexibility in order to maintain the efficiency and reliability of the system. It is also crucial that the resources that ensure long-term reliability are able to recover their costs to avoid reliability problems. A well-designed market should be technologically neutral, allowing competition between different technologies to meet system needs (Ela *et al.*, 2014).

The current reforms underscore the need for greater precision in energy management, both spatially and temporally. Growth in wind and solar generation brings increased demand for intraday trading and adjustments to production schedules based on forecasts and current market conditions (IRENA, 2019b). In a context of wide variability in generation, it becomes necessary to adapt market terms and settlement periods to maximize generators' flexibility. A system with a lot of variable renewable energy would benefit from shorter dispatch times and prices that reflect short-term market dynamics and provide generators with clear guidelines for modifying their output. Barroso *et al.* (2021) state that, in order to adequately reflect the uncertainty of wind and solar sources, prices should be set with a maximum time horizon of one hour.

Multi-settlement markets offer the advantage of enabling adjustments closer to the actual transaction. An LMP market with multiple settlements can efficiently handle the sudden starts and stops of generating units that occur when a significant amount of intermittent renewable generation units are present. In systems that operate with day-ahead (DAM) and real-time (RTM) markets, the DAM enables generators to set their production schedules in advance, respecting their specific operating constraints. Subsequently, the RTM provides a mechanism to make necessary adjustments to these previous schedules in response to eventualities or changes in the operating conditions of the power plants that were not foreseen in the DAM.

Mexico is currently the only country in Latin America and the Caribbean with both a day-ahead and a real-time market. The region has significant potential to refine its market structures, moving towards wholesale market models similar to those in Europe, which include intraday markets, or in the United States, which have real-time markets. According to Ribeiro *et al.* (2023), in a market with a high share of variable renewables there must be detailed real-time pricing, reflecting reliability needs and changes in supply and demand. It is essential to increase the frequency of prices and thus benefit from the flexibility of resources. It is also important to establish real-time markets close to dispatch and address spatial pricing accuracy. For instance, Mastropietro *et al.* (2020) have proposed that the Colombian market transitions from a single settlement design to a multiple settlement market including day-ahead, intraday, and balance markets.

In a context of high integration of wind and solar energy, the operator ISO-NE has proposed a number of measures in the U.S. (ENERSINC & SER Colombia, 2021). These include broadening the DAM optimization horizon to an approach that considers several days in the future, and introducing new ancillary services that provide the adaptability needed to manage trading day uncertainties. In addition, a seasonal forward market is suggested to encourage investments to meet the challenge of harsh winters. As can be seen, all these measures seek to adapt to a changing energy landscape.

Chile is currently analyzing a change in the design of its electricity market from an audited costs to a bid-based model. According to the regulatory body CEN (2023), given the increased presence of wind and solar energy, the current cost-based model requires large investments in storage and renewable sources to help maintain reliability, which can generate inefficiencies in the system. Therefore, the agency notes the importance of moving towards a market design based on energy, ancillary services, and capacity auctions. In mid-2023, Chile's National Energy Commission tendered a study entitled "Detailed design for the improvement of the national electricity market in the transition to a bidding market", with the goal of developing a detailed mechanism that would improve the current market, addressing multiple energy products, and serve as a foundation for Chile's energy transition.

The massive integration of solar and wind technology requires reconsidering different electricity dispatch designs to determine which is best suited to these technologies. Keay & Robinson (2018) propose a two-market dispatch design as a means to improve efficiency in the face of the increasing presence of intermittent renewables. The authors argue that traditional markets were structured in such a way that it was possible to differentiate between energy sources based on their short-run marginal costs and always opt for the most economical plants, to ensure both short- and long-term efficiency. This approach, however, presupposes the existence of dispatchable plants with variable marginal costs, a notion that will be irrelevant in the decarbonized market envisioned for the future. By 2027, wind and solar power generation is expected to account for 30% of the region's total. Given the near-zero marginal cost of these technologies, current markets face difficulties in adequately rewarding investments and sending clear signals to operators and consumers.

The simplest implementation of the two-market mechanism is as follows:

- **A first (economic) dispatch is made according to a certain criterion:** variable renewable energy generation—mainly solar and wind—in the case of the European Union's Internal Electricity Market. Under a similar scheme, the first dispatch in the Central American REM is made from domestic generation without considering imports or exports. In addition to selecting the bid, this type of dispatch requires specifying the demand to be met. This is not a trivial matter in the case of the EU, as it must decide how much of the demand will be met by variable renewable generation (although in theory the decision could be left to consumers).
- **The first dispatch determines bids for electricity injections (generation) and withdrawals (demand).**
- **A second dispatch carries the rest of the supply:** conventional generation in the case of the EU; bids to the REM of the national dispatches and of the regional generation itself, in the case of Central America.

A further and often overlooked issue is the pricing of overlapping dispatches. In the case of the EU, the prices of the first dispatch are determined by the costs resulting from renewable energy generation auctions (pay-as-bid), and the price of the second dispatch applies only to conventional energy generation (marginal).

Running two overlapping dispatches using the same transmission network necessarily leads to a suboptimal solution; the first dispatch is myopic with respect to what will be available in the second, and the second may in turn be unnecessarily constrained. If it were possible to have both sale and purchase bids for each of the markets, it would theoretically be possible to co-optimize both in a single dispatch and obtain separate prices and quantities for each. This alternative could be the only way to guarantee the efficient use of the transmission system used by both markets, i.e., transmission capacity would be allocated to the dispatch with the highest value. A practical implementation of two markets sharing the transmission network is discussed in Annex B.

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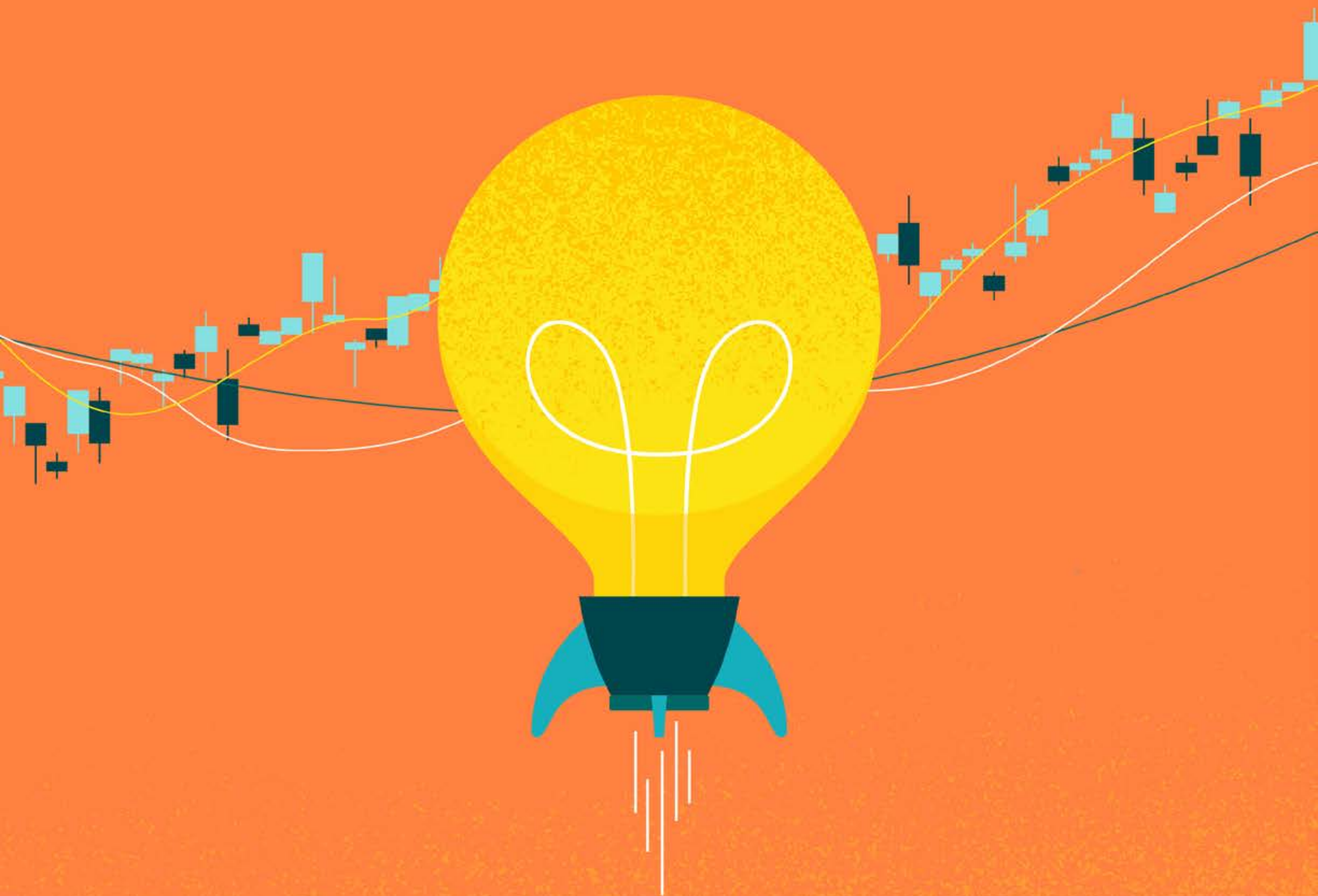
7 CONCLUSIONS



The purpose of this report is to contribute to the current debates on the construction of efficient, affordable, and sustainable wholesale markets in Latin America and the Caribbean. It is clear that after three decades of reforms in electricity markets in Latin America and the Caribbean, there is no single formula for their development and each country must adjust its strategies according to its context, resources, and particular needs, but it is also true that the recent global volatility of energy markets and the integration of VREs has highlighted the need to strengthen the resilience of the sector.

In Latin America and the Caribbean in particular, short-term electricity price volatility has been amplified by rising fuel costs and weather variations. Market inefficiencies only intensify this, and while—once again—each country has implemented a market design fitting its circumstances, it is vital to learn from global discussions and experiences. To meet future needs and support the transition to clean energy, it is essential to develop liquid and transparent short-term markets that enhance generation and consumption efficiency, as well as long-term markets that shield participants from price volatility and encourage efficient investment decisions. Efficient pricing and appropriate market signals are critical for the effective operation of both short- and long-term markets.

A starting point in understanding electricity price dynamics lies in understanding the design and structure of short-term electricity markets. Although merit order dispatch-based systems have been effective, there are opportunities for improvement in the prevailing structures in a context of the integration of new generation assets and increasing volatility in short-term electricity prices in Latin America and the Caribbean. The cost-based model, widely used in the region, could in some cases be replaced by bid-based markets to facilitate the energy transition. Additionally, the adoption of nodal markets with multi-settlement mechanisms could enhance the integration of variable. Likewise, the integration of flexible technologies will facilitate managing the variability and intermittency of solar and wind sources. While these policies aim to enhance efficiency, they also pose challenges, including the design of incentives for competition and ensuring system reliability in both the short and long term.

Each country has its own dynamics for determining short-term electricity prices. These dynamics are not only related to market design, but also to each country's specific electricity matrix. For example, in countries where fossil fuels predominate in the electricity matrix, such as Argentina and Mexico, electricity prices are strongly linked to natural gas prices. In countries with a higher reliance on hydroelectric power in their energy mix, such as Colombia or Brazil, water cycles play a critical role in influencing electricity prices. **Diversifying the energy matrix enhances the resilience of the system, ensuring stability even when one of the primary energy sources is impacted by external factors.**

Regional integration, such as that observed not only in Europe but also in the Electricity Interconnection System for Central American Countries (SIEPAC) and in various binational connections, is essential to **use resources more efficiently, increase system reliability, promote more competition in the markets and reduce average wholesale market prices.**

The European experience shows us that, in the face of escalating electricity prices, consumer purchasing power and business competitiveness must be protected. Policies implemented should focus on maintaining the purchasing power of the most vulnerable households, be temporary, and promote energy efficiency, while maintaining a stable regulatory framework that does not discourage investors. In addition, integrating more renewable sources into the energy matrix can reduce dependence on fossil fuels and improve the affordability of electricity by reducing prices in wholesale markets.

Progress in Latin American and Caribbean electricity markets is mixed. Some countries have already achieved deregulated wholesale structures that foster competition and follow some of the most internationally recognized practices, but they must continue to adapt to changing realities and challenges. In other countries, discussions are in their early stages and there is still much work to do. **Regardless of the particular context in which it is read, this work contains lessons learned at the national, regional, and global levels; we trust that it will be useful to anyone responsible for creating or further developing safer, more efficient, and more affordable electricity markets in Latin America and the Caribbean.**

8 ANNEXES

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ANNEX A

Expansion of generation, marginal power markets, and marginal costs

This Annex shows, very simply and succinctly, the most relevant concepts involved in the expansion of generation, as well as their relationship with marginal electricity markets and Time o Use supply tariffs.

To address the aforementioned topics, we will first explain the concept of total generation costs, which considers both investment costs and variable operating costs (including fuel costs). The total unit costs in the long term correspond to the levelized generation costs, which are widely used to easily and roughly compare different generation technologies in the planning stage of generation expansion. The levelized cost is calculated as the net present value of all costs (investment, fuel, and operation and maintenance) of a plant over its lifetime, divided by the net present value of all energy produced by the plant, also over its lifetime, as shown in the equation below (1). Total unit costs are, simply put, the average total costs—also known as total average costs—i.e. the sum of variable costs and fixed costs divided by the total generation of a power plant, all for a given period. If the generation expansion planning accounts for only one period (e.g., to keep the discussion as simple as possible, the examples in this Annex use one week and disregard the discount rate), and the demand is accurately known, then the total unit costs are equivalent to the levelized costs.

(1)

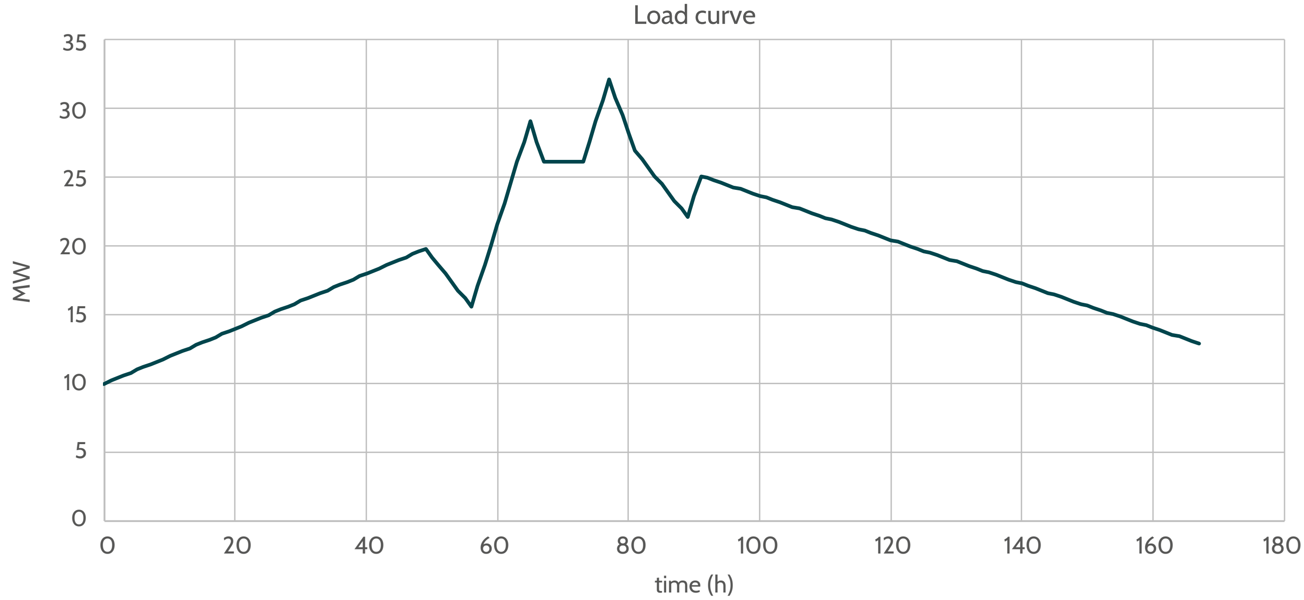
$$Levelized\ costs(LCOE) = \sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t} / \sum_{t=1}^{n} \frac{E_t}{(1+r)^t}$$

Where:

I_t	Investment expenditure in year t (including financing)
M_t	Operating and maintenance (O&M) costs in year t
F_t	Fuel costs in year t
E_t	Amount of electricity generated in year t
r	Discount rate
n	Plant life span

It is important to note that all data used in this Annex are purely hypothetical and are intended only to show the most relevant concepts used in generation expansion planning. They also show that the use of total unit costs to carry out dispatch, once investment decisions have been made and carried out, does not make economic sense. For the sake of simplicity, the expected demand for one week (168 hours) is used for a hypothetical system, as shown in the following Figure A. 1. In other words, the problem is to find the optimal generation portfolio to satisfy this demand (or load) curve.

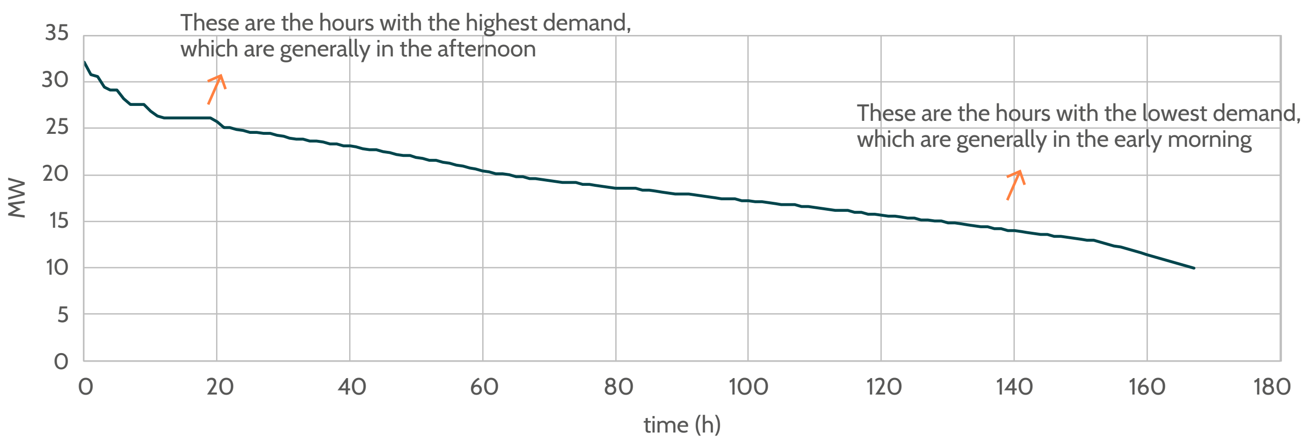
FIGURE A.1. Load Profile



Source: Compiled by the authors.

Sorting demand from highest to lowest, we obtain the load duration curve (LDC) shown in Figure A. 2. The LDC represents the same data as the Load Curve; it is constructed by arranging the demand values in decreasing order, i.e. the highest demands on the left side and the lowest on the right side. Any point on the LDC depicts the duration (in hours) for which the demand is greater than or equal to the demand at that point.

FIGURE A.2. Load duration curve, LDC



Source: Compiled by the authors.

On the generation side, and for the sake of simplicity, only three types of generation technologies are considered available (the names of the technologies are for explanation purposes only): ***H*** (hydroelectric), ***CC*** (combined cycle) and ***TG*** (turbo gas). The essential economics of generation are shown in Figure A. 3, where the ***total costs per MW of installed capacity*** (to be determined), i.e. capital costs plus operating costs (including fuel) ***depending on the number of operating hours*** are shown. Energy Not Supplied (ENS), i.e. load shedding or supply interruption, is included as an additional "technology". Including ENS as an additional technology available for decision making in generation expansion planning is the traditional way of balancing economics and reliability, as explained later in this Annex.

TG has low capital costs (***itg***), represented by the intersection of its curve with the y-axis (investment costs per week) but has high operating costs (***vtg***), represented by the slope of its curve. ***CC*** has higher investment costs (***icc***) than ***TG***, but lower operating costs (***vcc***) due to its high efficiencies. H has higher investment costs (***ih***) than CC, but very low operating costs (***vh***) due to its input (water) being practically zero cost. Table A. 1 below shows investment (fixed) costs and variable operating costs. For the ENS, or load shedding, there is a fixed cost of 0.0, i.e. no investment is needed, but it has a very high variable cost, i.e. the economic impact of load shedding.

TABLE A.1. **Fixed and variable costs of the various technologies**

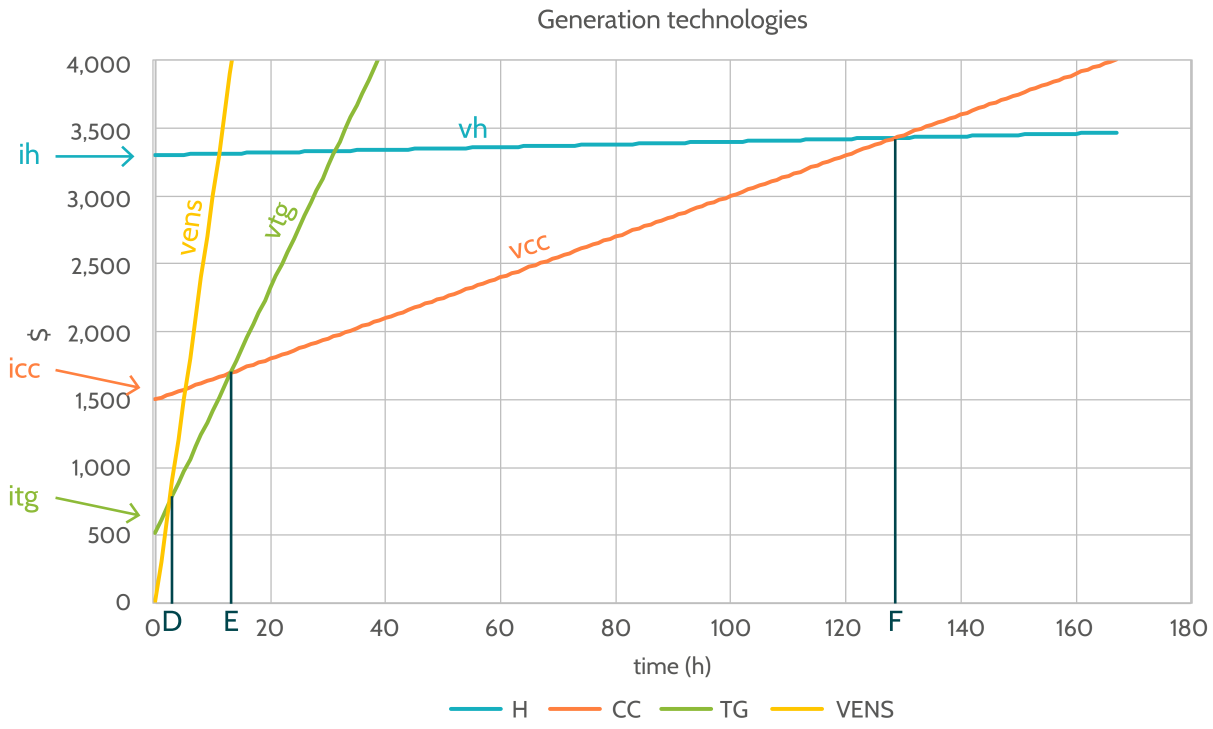
Technology	Fixed costs ($/MW-week)*	Variable costs ($/MWh)*
H	3,300.0	1.0
CC	1,500.0	15.0
TG	520.0	90.0
ENS	0.0	300.0

Source: Compiled by the authors.
Note: *Fixed and variable costs are hypothetical to conceptually show their impact.

Figure A. 3 shows the generation cost curves for each of the various technologies in relation to their hours of operation, as well as the value of energy not supplied (VENS). The generation cost curves are formed by indicating the fixed cost of each plant at the beginning of the graph (time 0) and continue to grow linearly from that point with their respective variable costs and hours of operation. The letters **D**, ***E***, and **F** on the horizontal axis are used as markers where the cost curves of the technologies analyzed intersect.

Thus, from an economic point of view, ***TG*** is more expensive than ***CC*** if more than ***E*** hours are operated. Similarly, ***H*** is cheaper if it operates more than ***F*** hours, and if it operates less than ***D*** hours it is more economical to shed load, according to the VENS. Thus, in generation expansion, ***one of the ways to explicitly consider reliability is to model unsupplied power as an additional generator, with zero investment costs, but very high operating costs, equal to the Value (or Cost) of Energy Not Supplied (VENS or CENS).*** VENS is a measure of the economic impact of supply interruptions and represents the limit of the price that demand is willing to pay for supply.

FIGURE A.3. **Generation cost curves**



Source: Compiled by the authors.

The total unit costs for each technology are the slope of the line between the origin and the intersection of the line with the cost curve of the technology for a given duration (in hours), as shown in equation (2).

(2)

$$Total\ costs\ (energized) = (Fixed\ Cost + Variable\ Cost)/MWh$$

Next, we will calculate the total cost for each of the technologies in relation to the number of hours of operation:

Turbo Gas Power Plant

The Fixed Cost for the Turbo Gas Plant is $520/MW, obtained from Table A. 1, and the Variable Cost for this plant is obtained from Figure A. 3, at the intersection of the generation cost curve and the number of hours of operation, i.e., the Variable Cost obtained from Table A. 1 multiplied by the number of hours of operation. Once the inputs have been obtained to calculate the total unit costs, we use equation (2).

i) If it operates 60 hours, the average cost will be:

Fixed costs plus variable costs = $520/MW + ($90/MWh*60h) = $5,920/MW

$$\text{Total unit costs} = \frac{\$5{,}920/MW}{60h} = \underline{\boldsymbol{98.67\ \$/MWh}} = \left(\frac{\$520/MW}{60h}\right) + \$90/\text{MWh} = \$\boldsymbol{8.67/MWh} + \$90/\text{MWh}$$

ii) But if it operates 160 hours, the average cost will be:

Fixed costs plus variable costs = $520/MW + ($90/MWh*160h) = $14,920/MW

$$\text{Total unit costs} = \frac{\$14{,}920/MW}{160h} = \underline{\boldsymbol{93.25\ \$/MWh}} = \left(\frac{\$520/MW}{160h}\right) + \$90/\text{MWh} = \$\boldsymbol{3.25/MWh} + \$90/\text{MWh}$$

iii) And if it operates 100 hours, the average cost will be:

Fixed costs plus variable costs = $520/MW + ($90/MWh*100h) = $9,520/MW

$$\text{Total unit costs} = \frac{\$9{,}520/MW}{100h} = \underline{\boldsymbol{95.20\ \$/MWh}} = \left(\frac{\$520/MW}{100h}\right) + \$90/\text{MWh} = \$\boldsymbol{5.20/MWh} + \$90/\text{MWh}$$

Hydroelectric Power Plant

The fixed cost for the hydroelectric plant is $3,300/MW, obtained from Table A. 1, and the Variable Cost for this plant is obtained from Figure A. 3, at the intersection of the generation cost curve and the number of hours of operation, i.e., the Variable Cost obtained from Table A. 1 multiplied by the number of hours of operation. Once the inputs have been obtained to calculate the total unit costs, we use equation (2).

i) If it operates 60 hours, the average cost will be:

Fixed costs plus variable costs = $3,300/MW + ($1/MWh*60h) = $3,360/MW

$$\text{Total unit costs} = \frac{\$3{,}360/MW}{60h} = \underline{\boldsymbol{56.00\ \$/MWh}} = \left(\frac{\$3{,}300/MW}{60h}\right) + \$1/\text{MWh} = \$\boldsymbol{55/MWh} + \$1/\text{MWh}$$

ii) If it operates 160 hours, the average cost will be:

Fixed costs plus variable costs = $3,300/MW + ($1/MWh*160h) = $3,460/MW

$$\text{Total unit costs} = \frac{\$3{,}460/MW}{160h} = \underline{\boldsymbol{21.625\ \$/MWh}} = \left(\frac{\$3{,}300/MW}{160h}\right) + \$1/\text{MWh} = \$\boldsymbol{20.625/MWh} + \$1/\text{MWh}$$

iii) And if it operates 100 hours, the average cost will be:

Fixed costs plus variable costs = $3,300/MW + ($1/MWh*100h) = $3,400/MW

$$\text{Total unit costs} = \frac{\$3{,}400/MW}{100h} = \underline{\boldsymbol{34.00\ \$/MWh}} = \left(\frac{\$3{,}300/MW}{100h}\right) + \$1/\text{MWh} = \$\boldsymbol{33.00/MWh} + \$1/\text{MWh}$$

Combined Cycle Power Plant

The fixed cost for the Combined Cycle power plant is $1,500/MW, obtained from Table A. 1, and the Variable Cost for this plant is obtained from Figure A. 3, at the intersection of the generation cost curve and the number of hours of operation, i.e., the Variable Cost obtained from Table A. 1 multiplied by the number of hours of operation. Once the inputs have been obtained to calculate the total unit costs, we use equation (2).

i) If it operates 60 hours, the average cost will be:

Fixed costs plus variable costs = $1,500/MW + ($15/MWh*60h) = $2,400/MW

$$\text{Total unit costs} = \frac{\$2{,}400/MW}{60h} = \underline{\boldsymbol{40.00\ \$/MWh}} = \left(\frac{\$1{,}500/MW}{60h}\right) + \$15/\text{MWh} = \$\boldsymbol{25/MWh} + \$15/\text{MWh}$$

ii) But if it operates 160 hours, the average cost will be:

Fixed costs plus variable costs = $1,500/MW + ($15/MWh*160h) = $3,900/MW

$$\text{Total unit costs} = \frac{\$3{,}900/MW}{160h} = \underline{\boldsymbol{24.375\ \$/MWh}} = \left(\frac{\$1{,}500/MW}{160h}\right) + \$15/\text{MWh} = \$\boldsymbol{9.375/MWh} + \$15/\text{MWh}$$

iii) And if it operates 100 hours, the average cost will be:

Fixed costs plus variable costs = $1,500/MW + ($15/MWh*100h) = $3,000/MW

$$\text{Total unit costs} = \frac{\$3{,}000/MW}{100h} = \underline{\boldsymbol{30.00\ \$/MWh}} = \left(\frac{\$1{,}500/MW}{100h}\right) + \$15/\text{MWh} = \$\boldsymbol{15/MWh} + \$15/\text{MWh}$$

The above calculations show how the average total cost is highly dependent on the ***plant factor (pf)*** (how many hours the plant generates at full load, i.e., the use rate). The values shown are for plant factors of 36% (60/168), 95% (160/168), and 60% (100/168), i.e., the number of hours the plant operates in a week (60,160,100), divided by the number of hours in the week (24*7=168).

TABLE A.2. Average costs of different technologies for different plant factors

		Total Costs ($)				Average Costs ($/MWh)*			
time	pf	H	CC	TG	VENS	Hm	CCm	TGm	VENSm
1	1%	3,301	1,515	610	300	3,301	1,515	610	300
10	6%	3,310	1,650	1,420	3,000	331	165	142	300
40	24%	3,340	2,100	4,120	12,000	84	53	103	300
60	36%	3,360	2,400	5,920	18,000	56	40	99	300
100	60%	3,400	3,000	9,520	30,000	34	30	95	300
160	95%	3,460	3,900	14,920	48,000	22	24	93	300

Source: Compiled by the authors.
Note: *The shaded and bolded values are the lowest Average Costs for each technology for each plant factor.

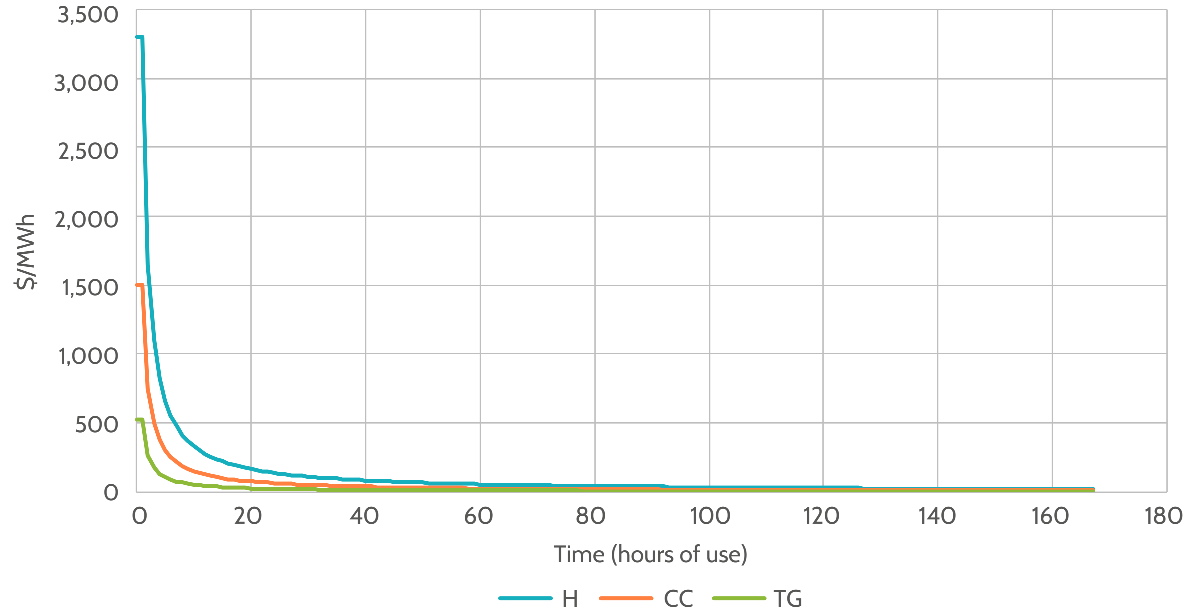
Table A. 2 shows the total unit costs for different plant factors.

Table A. 2 clearly shows that, if the plant is used with a 95% plant factor, the cheapest option in terms of average costs is an H plant ($22/MWh); at the other extreme, if a plant is used only 6% of the time, the best option is TG ($142/MWh). The CC option is intermediate between H and TG.

One important aspect to highlight is that the investment costs, once the decision is made and the plant is built, do not change, no matter how much energy the plant produces, or the amount of time it is used, or even if the plant ceases to operate altogether. For example, when taking out a loan for the purchase of a car, the monthly payments (which include interest) have to be paid, regardless of whether the car is parked, whether it is used only on weekends, whether it is used as an Uber, whether the car is stolen, etc.

Figure A. 4 shows the average fixed costs according to the energy generated (the use rate of a power plant or plant factor). We can see that the more a plant is used, the lower the average fixed cost, as the investment costs (capital) are spread over more generation (MWh). Thus, if the CC is used for only one hour, the average investment cost will be $1,500/MWh, but if it is used for 100 hours (producing 100 MWh) the average investment cost will be $15/MWh.

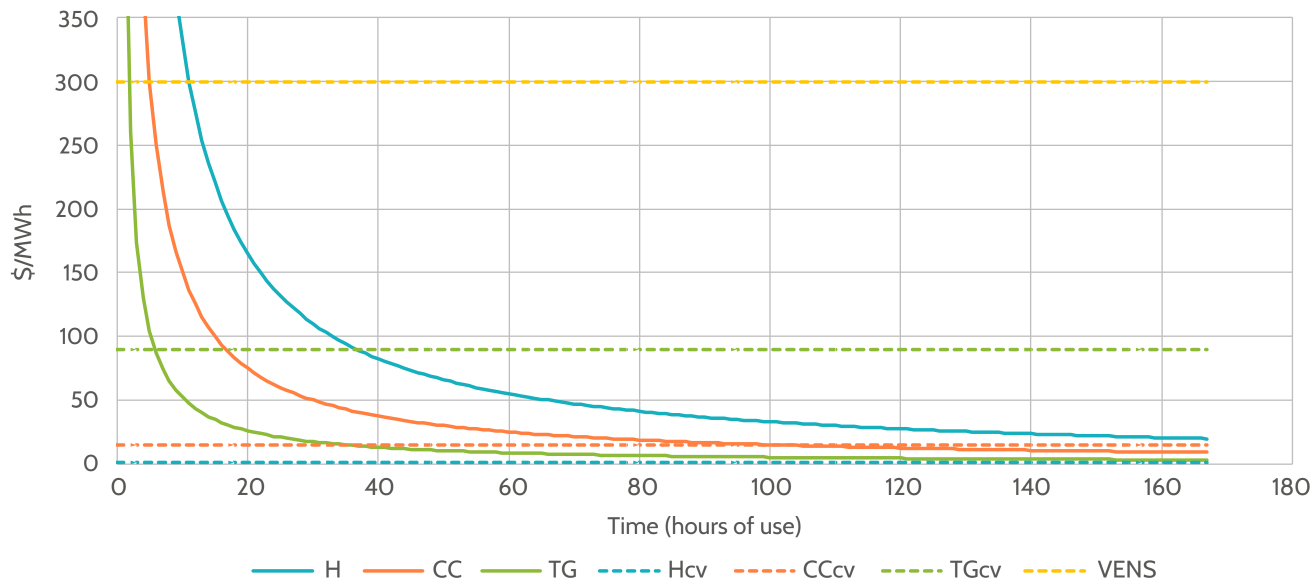
FIGURE A.4. **Average investment costs**



Source: Compiled by the authors.

The variable costs (basically, fuels) that remain constant (slopes of the curves of Figure A. 3), and which account for the cost of generating 1 additional MWh, —also known as marginal costs—are shown in Figure A. 5 (dotted lines), together with the average fixed costs (solid lines).

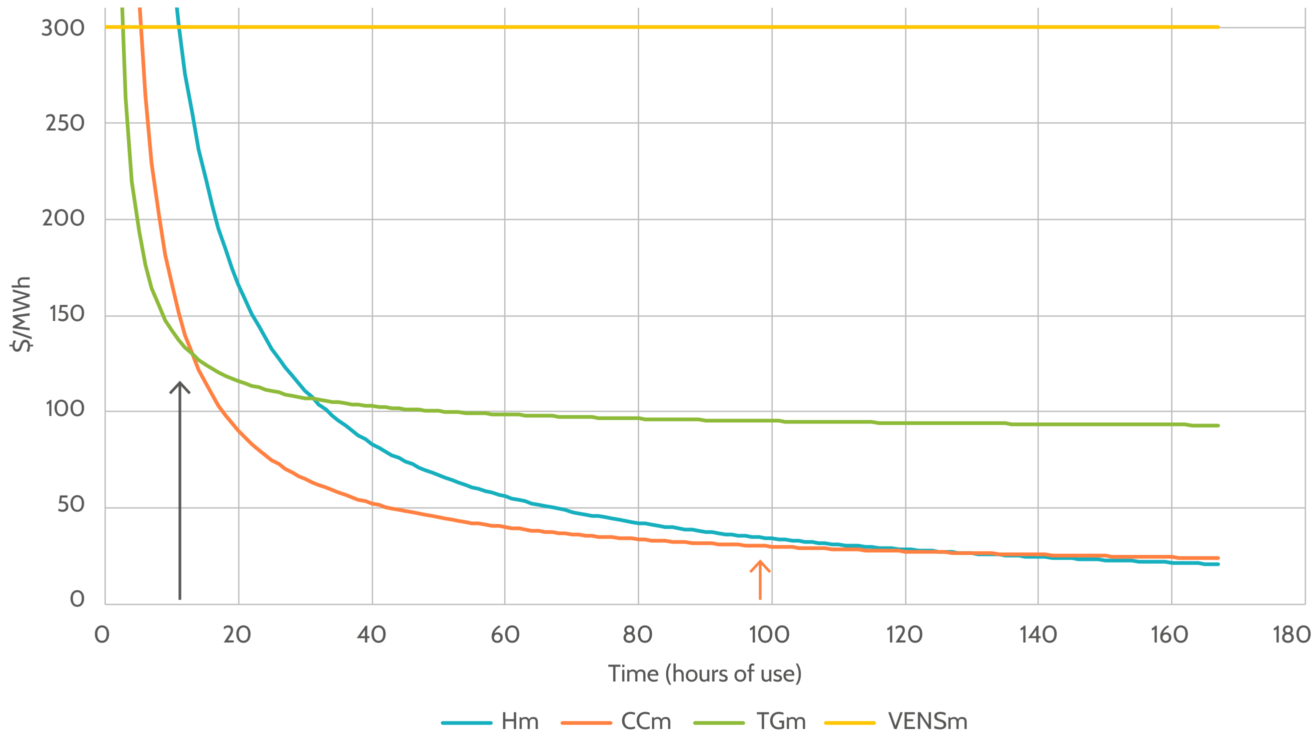
FIGURE A.5. **Average, fixed, and variable costs**



Source: Compiled by the authors.

Finally, Figure A.6 shows the total average costs (fixed + variable). Thus, if a plant is used less than ~13 or 14 hours (shown in the figure with a gray arrow), the cheapest option is ***TG***. Similarly, if the plant is used more than ~128 or 129 hours (shown in the figure with an orange arrow), the cheapest option is ***H***. Assuming that fuel costs (adjusted for inflation) remain the same, the total average costs represent the ***total unit costs***. It should be emphasized that a basic premise for determining average costs is the plant factor. For example, in Figure A.6 we see that for a plant factor of 10 hours/168 hours, TG is cheaper than CC and much cheaper than H. For a plant factor of 100/168, however, TG is extremely expensive compared to CC and H. The plant factor of a power plant is the quotient between the actual energy generated by the power plant during a set period (usually on an annual basis, although here a weekly period is used) and the energy generated if it had worked at full load during that same period.

FIGURE A.6. **Total average costs (fixed + variable)**



Source: Compiled by the authors.
Note: *VENS is a measure of the economic impact of supply interruptions and represents the limit of the price that demand is willing to pay for supply.

Using the concepts introduced above, the basic idea for determining the optimal generation portfolio to meet the demand shown in Figure A. 7, projecting the intersections of the cost curves of the various technologies onto the load duration curve.

It is therefore evident that the optimal generation portfolio will be to install enough ***H*** generation to satisfy base load, ***CC*** for intermediate load, and ***TG*** for peak load.

Figure A. 7 shows the traditional approach to both generation expansion and the establishment of Time of Use supply tariffs with energy charges for the base, intermediate, and peak periods based on the variable costs of the corresponding technologies (***H, CC, TG***) and demand payments based on the fixed costs (including investment costs) of the "peaker" plants (***TG***). For an optimally expanded and operated system, such payments guarantee cost recovery for all technologies. "Peaker" generation plants are those that are used very few hours (in a year) and serve to meet demand peaks, so the cheapest option are generators with low investment costs and high operating costs (that represent a low total value due to the few operating hours).

For marginal (energy only) electricity markets, marginal prices are determined by the marginal generator, or the value of energy not supplied (VENS). In markets that include capacity charges, in an optimally expanded and operated system, the capacity/power price would be the investment cost of the peaker plant (TG), and marginal prices would be determined by the marginal plant, as shown in Figures A.9 and A.10.

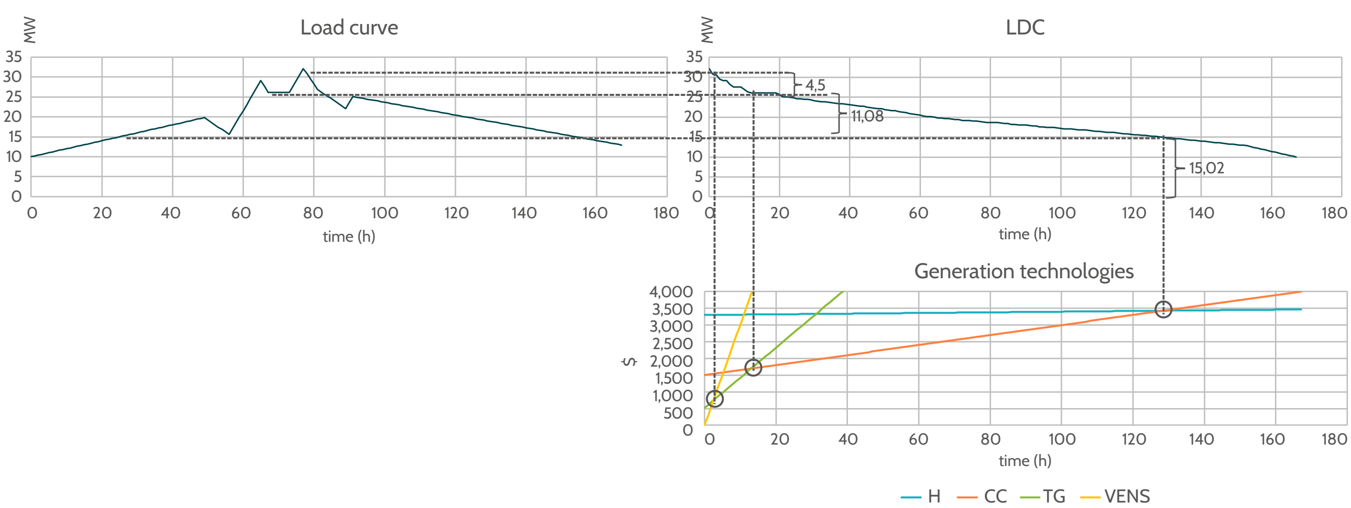
A computer program for optimal generation expansion yields the following results (although, for a case as simple as this one, the result can be obtained graphically in a rough manner, as shown in Figure A.7):

TABLE A.3. Optimal generation expansion portfolio

Technology	MW
H	15.02
CC	11.08
TG	4.5

Source: Compiled by the authors.

FIGURE A.7. Determining the optimal generation portfolio



Source: Compiled by the authors.

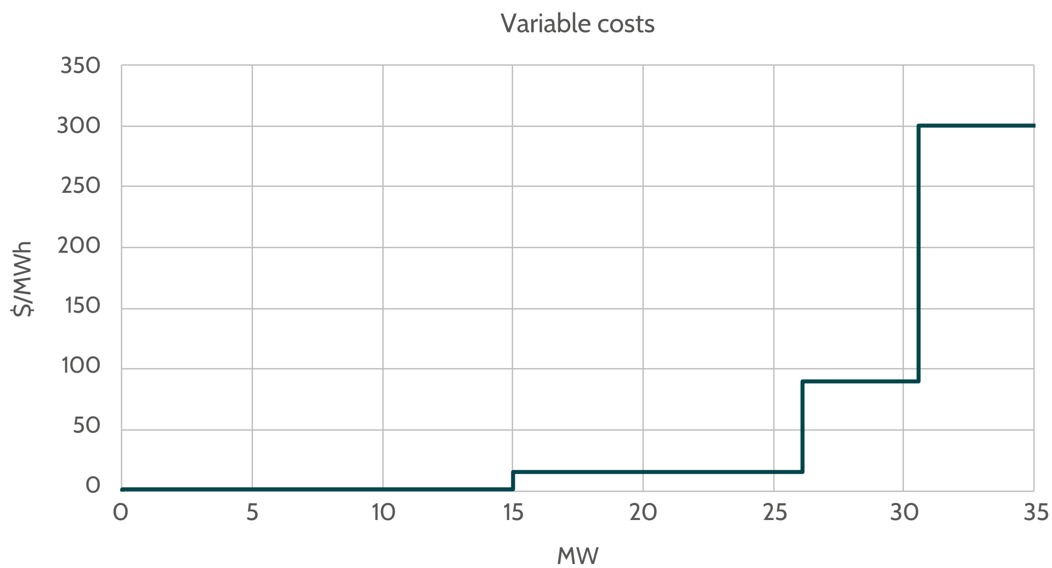
Once the investment decisions and the actual investments have been made, the corresponding costs are sunk costs (regardless of whether the power plants are used or not, loans, contracts, etc., must be paid). Following the car example, if after buying the car (and committing to pay the monthly installments), you win another car in a raffle, you will have practically no investment cost (only the price of the ticket). If the second car is less efficient (uses twice as much gasoline per km as the purchased car) than the first car, the purchased car should be used first, and the second car from the raffle should only be used when the first (purchased) car is already being used, e.g. if you have to make a 168-hour trip, and a 10-hour trip simultaneously, it is obvious that you should use the more efficient (purchased) car to make the 168-hour trip, and the less efficient (raffle) car for the shorter 10-hour trip. Doing it the other way around would be the wrong decision as it would waste more gasoline.

The "dispatch" of cars must follow the same principles as an economic generation dispatch.

For economic dispatch, only variable costs should be considered. The ranking of the different technologies is shown in Figure A. 8.

Thus, the technologies with the lowest operating costs, i.e. ***H***, are used first for dispatch, followed by ***CC*** and finally ***TG***, and, if necessary, load shedding is used, as shown in Figure A.9 and Figure A.10.

FIGURE A.8. **Generation merit order**



Source: Compiled by the authors.

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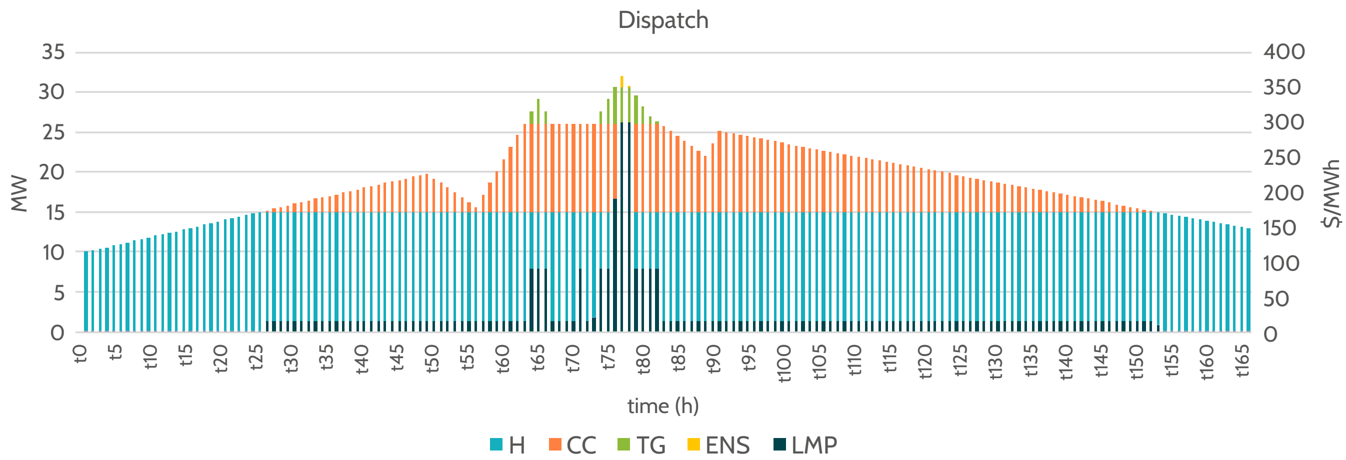
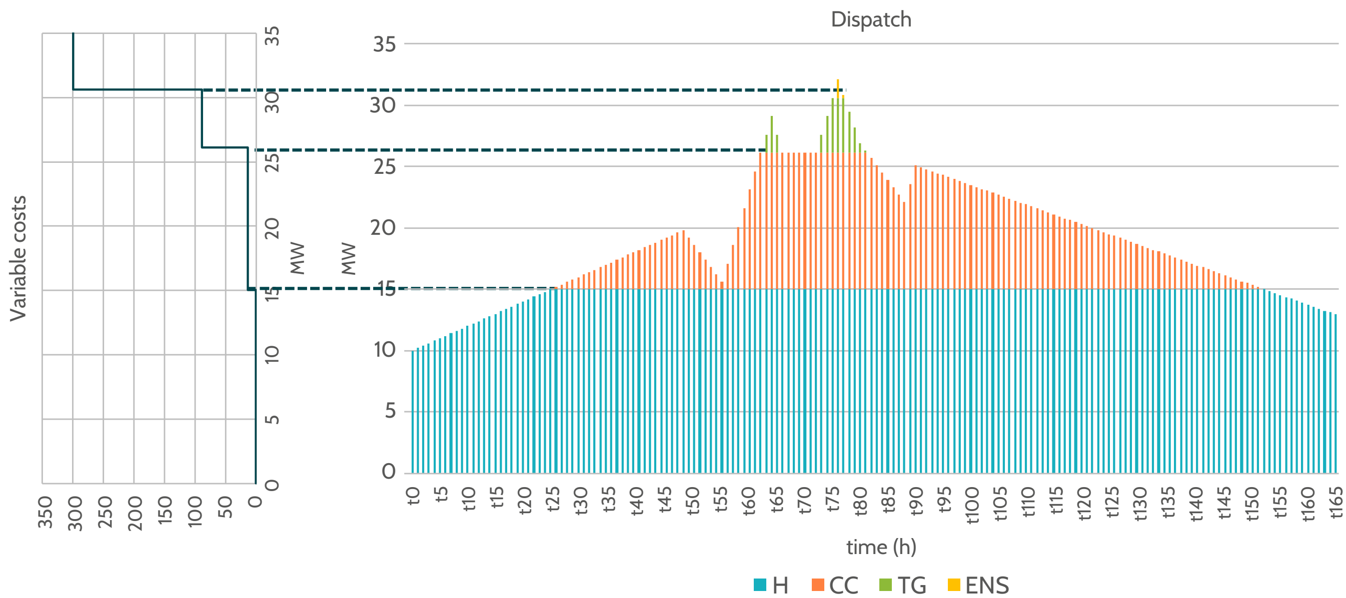
FIGURE A.9. Optimal generation dispatch



Source: Compiled by the authors.

FIGURE A.10. Optimal generation dispatch



Source: Compiled by the authors.

Thus, to determine the optimal generation portfolio, we consider the expected demand curve, generation investment costs, as well as fuel and operation and maintenance costs. The generation expansion exercise is generally performed annually with a long-term horizon (15 to 20 years). **Once the investments in generation have been made, the generation dispatch is performed considering only variable costs.**

Performing the generation dispatch considering the total unit costs requires knowing the plant factor, to be able to calculate the total average costs. If we assume that historical values are used, and assuming that the week prior to the week of dispatch the plant factor for the power plants was 36% for H, 60% for CC, and 6% for TG, the ranking of the total unit costs would be as follows:

We can see that, using average costs, the cheapest plant would appear to be the **CC** plant, such that the **H** plant would only be used when the **CC** plant is at full load, i.e. when demand exceeds the capacity of the **CC** plant (11.08 MW).

Figure A.11 shows the dispatch using average costs, and Table A.5 and Table A.6 show a summary of the costs incurred.

We can observe that, under this new dispatch mechanism, using average costs, there is an increase in total variable costs of $15,846.60 ($32,435.78 - $16,589.18), which represents 96%, due to a higher dispatch of energy from the CC plant, which leads to a lower dispatch of the H plant (plant with lower variable costs).

TABLE A.4. Merit order using average costs

Technology	Average Costs ($/MWh)
CC	30
H	56
TG	142
ENS	300

Source: Compiled by the authors.

TABLE A.5. Dispatch based on variable and average costs

Technology	Fixed costs ($/MW-week)	Variable costs ($/MWh)	Installed MW	Fixed costs ($)	Dispatch with variable costs		Dispatch with total unit costs	
					Production (MWh)	Total variable costs ($)	Production (MWh)	Total variable costs ($)
H	3,300.00	1.00	15.02	49,566.00	2,443.28	2,443.28	1,311.38	1,311.38
CC	1,500.00	15.00	11.08	16,620.00	726.06	10,890.90	1,857.96	27,869.40
TG	520.00	90.00	4.50	2,340.00	30.50	2,745.00	30.50	2,745.00
ENS	0.00	300.00	0.00	0.00	1.70	510.00	1.70	510.00
Totals			30.60	68,526.00	3,201.54	16,589.18	3,201.54	32,435.78

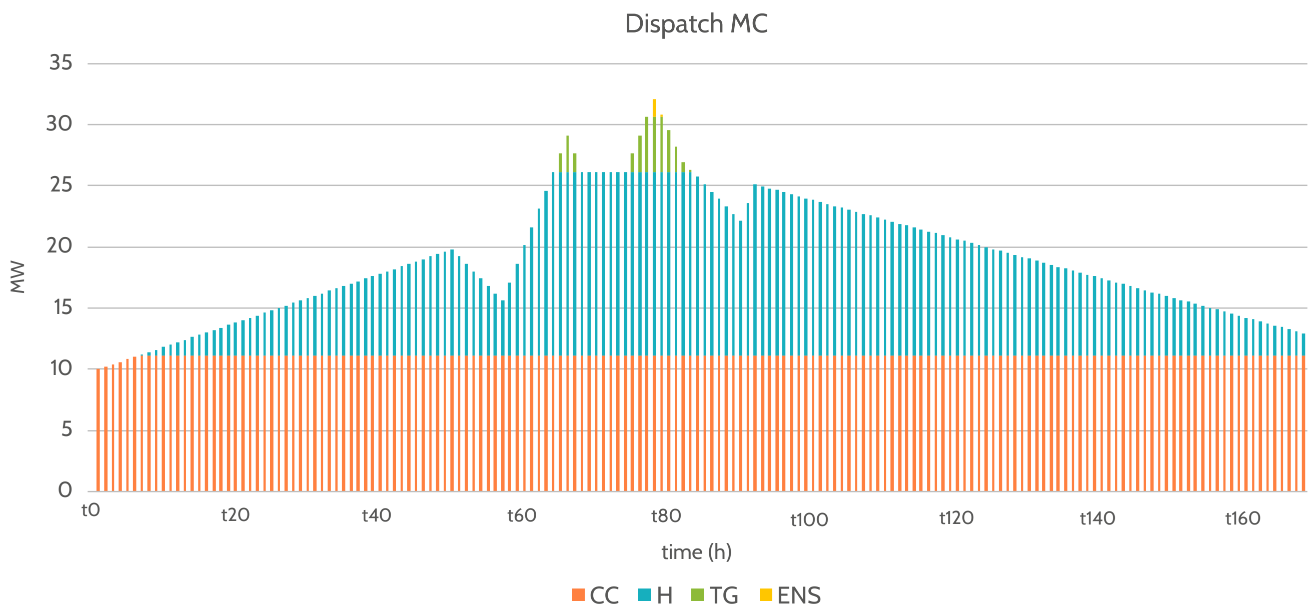
Source: Compiled by the authors.

TABLE A.6. Total variable costs with variable costs and average costs

Technology	Dispatch with variable costs	Dispatch with total unit costs
	Total variable costs ($)	Total variable costs ($)
H	2,443.28	1,311.38
CC	10,890.90	27,869.40
TG	2,745.00	2,745.00
ENS	510.00	510.00
Totals	16,589.18	32,435.78
96% increase in generation costs using full unit costs		

Source: Compiled by the authors.

FIGURE A.11. Generation dispatch based on total unit costs



Source: Compiled by the authors.

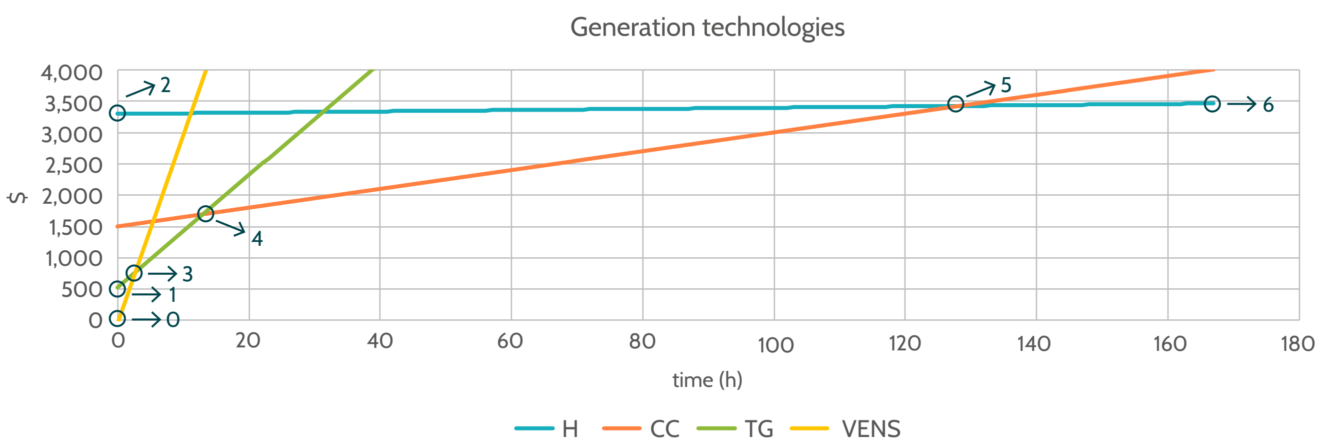
In a marginalist market, infra-marginal plants receive the marginal price, i.e., the variable cost of the most expensive dispatched plant. Such revenues over and above its variable costs are necessary to exactly recover its fixed costs (investment), e.g., if plant ***H*** is operated for 168 hours:

$\text{Revenue} = ih + vh*168$	This equation is direct, i.e., investment costs plus variable costs are paid for the number of operating hours.
$= itg + E*vtg + (F-E)*vcc + (168-F)*vh$	This formula is the basis for setting hourly rates with capacity charges. The capacity charge is equal to the investment cost of the peaker plant (itg), and the hourly prices for the peak (vtg), intermediate (vcc), and base (vh) periods correspond to the variable costs of the marginal technology of the corresponding period. This formula is also the basis for marginal electricity markets that include a capacity/power market.
$= D*VENS + (E-D)*vtg + (F-E)*vcc + (168-F)*vh$	This equation is the basis for the "pure" marginalist electricity markets, i.e. "energy only", where prices can be triggered at VENS for short periods but necessary to recover costs and avoid the "missing money" problem.

Figure A.12 shows the equivalences of the three equations above, i.e., arriving at point **6** (which represents on the y-axis the revenue needed for an ***H*** plant operating 168 hours) from the origin (point **0**) we can do:

- **0** to **2** and **2** to **6**
- **0** to **1**, **1** to **4**, **4** to **5** and **5** to **6**
- **0** to **3**, **3** to **4**, **4** to **5** and **5** to **6**

FIGURE A.12. Generation cost curves



Source: Compiled by the authors.

ANNEX B

Mathematical model of the economic dispatch with two markets

1.1 Introduction

The mathematical model of the economic dispatch problem, described below, attempts to capture the essential characteristics of generation dispatch, and its essential objective is to show—albeit somewhat conceptually—the impacts of the implementation of an energy policy with "two markets". The nomenclature used in the mathematical formulas is listed at section 1.2. Mnemonic names of variables and parameters have been used to facilitate the reading of the equations that make up the model.

1.2 Mathematical Model

Economic dispatch is the short-term calculation of the optimal use of a series of power generation units to meet system demand at the lowest possible cost, subject to operating constraints of the generating plants and the transmission system that guarantee the security of the dispatch.

Thus, the economic dispatch problem is determined by the following equations:

(3)

$$Max \left\{ \sum_{d,h} \{PriceDem_{d,h} \cdot Pd_{d,h} \cdot Duration_h\} - \sum_{g,h} \{PriceEGen_g \cdot Pg_{g,h} \cdot Duration_h\} \right\}$$

Subject to:

(4)

$$Pgmin_{g,h} \leq Pg_{g,h} \leq Pgmax_{g,h} \qquad \forall g, h$$

(5)

$$Pdmin_{d,h} \leq Pd_{d,h} \leq Pdmax_{d,h} \qquad \forall d, h$$

(6)

$$\sum_j B_{i,j} \cdot \theta_{j,h} = Pnetinj_{i,h} \qquad \forall h, i$$

(7)

$$F_l^{min} \leq \frac{1}{X_l}(\theta from_{l,h} - \theta to_{l,h}) \leq F_l^{max} \qquad \forall l, h$$

(8)

$$Pnetinj_{i,h} = \sum_{g \in \psi_i} Pg_{g,h} - \sum_{d \in \vartheta_i} Pd_{d,h} \qquad \forall h, i$$

(9)

$$\sum_{g \in MktA} Pg_{g,h} = \sum_{d \in MktA} Pd_{d,h} \qquad \forall h$$

(10)

$$\sum_{g \in MktB} Pg_{g,h} = \sum_{d \in MktB} Pd_{d,h} \qquad \forall h$$

The economic dispatch objective function, equation (3), maximizes the total economic surplus, that is, the difference between the value given by demand to the energy supply, minus the cost of generating said energy; in other words, the maximization of the objective economic dispatch function is to optimize the production of the generation units to supply the demand at the lowest cost while complying with the System's security constraints. **Constraints, on the other hand, represent physical limitations of the generation, demand, and transmission system.**

Constraint (4) represents the simple generation limits and ensures that the generation produced by the power plants is kept within the physical allowable levels. A generator cannot have a production level outside its operating limits, i.e., it cannot generate more than its maximum generation capacity, nor less than its minimum operating level. Constraint (4) can be read as follows: the produced generation (Pg) of generator (g) in hour (h) must be greater than or equal to the minimum allowed generation ($Pgmin$) of generator (g) in hour (h) and, also, less than or equal to the maximum allowed generation (*Pgmax*) of generator (g) in hour (h).

Constraint (5) represents the simple limits of demand and ensures that the demand is within its minimum and maximum limits. Demand is elastic[32] within the ranges offered, i.e., no more demand can be dispatched than that offered to be purchased or forecasted by the market operator. In the dispatch model used, the demand price is the cost of energy not supplied. Constraint (5) can be read as follows: the delivered demand (Pd) of the demand node (d) in hour (h) must be greater than or equal to the minimum demand ($Pdmin$) –in our current simulations this value is zero–, in hour (h) and, also, it must be less than or equal to the maximum demand ($Pdmax$), in hour (h).

Constraint (6) represents the nodal balance. This equation reflects Kirchhoff's laws. It is the simplest formulation of the power flow problem and allows, from net power injections (generation - demand) at each node, to calculate the power flows in the transmission lines and corridors, i.e., it is a mathematical equation needed by the model to represent the equilibrium at each node of the system.

Constraint (7) represents the limits of the transmission lines and ensures that the power flow through these lines is within their operating limits. The power flow in the transmission lines—the central part of the equation—must be maintained between its minimum (minimum flow, F^{min}) and maximum (maximum flow, F^{max}) for each line (l) in each hour (h), in order to maintain the security of the system operation.

Equation (8) represents the net power injected at each node of the system and quantifies the total amount of power injected or withdrawn from a node.

Equations (9) and (10) represent the balance for each of the markets[33] (hourly), i.e., the total generation of each market satisfies the total demand of that market hour per hour. In a "conventional" dispatch model, these restrictions do not exist, and although mathematically their implementation is very simple, the implications in terms of dispatched quantities (MW) and especially in terms of prices can have a significant impact, as shown in the examples that follow.

In a conventional economic dispatch, the Nodal (or Local) Marginal Prices are a by-product of the solution to the problem; they are the LaGrange Multipliers of the nodal balancing equations (6), colloquially defined as the marginal change in the objective function to satisfy a marginal increase in demand at the specific node.

The additional constraints of the global balance of each market, however, imply that the LaGrange Multiplier of such constraints must be considered to calculate nodal prices associated to each of the markets, i.e. there will be two sets of nodal prices.

[32] The demand of a system is considered elastic if it can change as a result of energy prices or other external factors and not be fully dispatched.

[33] In the European Union, the discussion has focused on the separation between renewable and variable conventional sources.

Nomenclature

h	Index. Hour or number of hours.
i,j	Index. Node.
l	Index. Transmission line.
g	Index. Generator.
d	Index. Demand (load).
$PriceDem_{d,h}$	Parameter. Price of demand d in period h. By default, it is the price or value of the energy not supplied.
$Pd_{d,h}$	Variable. Power supplied for demand d, in period h.
$Pdmin_{d,h}$	Parameter. Minimum power demanded by load d, of the modeled system in period h. By default, it is 0.
$Pdmax_{d,h}$	Parameter. Maximum power demanded by load d, of the modeled system in period h.
$Duration_{h}$	Parameter. Duration of period h expressed in hours.
$PriceEGen_{g}$	Parameter. Power price for generator g.
$Pg_{g,h}$	Variable. Power generated from generator g in period h.
$Pgmin_{g,h}$	Parameter. Minimum power generation limit of generator g in period h. By default $Pgmin_{g,h}=0$.
$Pgmax_{g,h}$	Parameter. Maximum power generation limit of generator g in period h.
B	Parameter. Bbus Matrix (Direct Current Power Flow Model).
$\theta_{i,h}$	Variable. Phase angles of node i in period h.
$Pnetinj_{i,h}$	Variable. Net power injected at node i in period h.
X_{l}	Parameter. Reactance of line l.
$\theta from_{l,h}$	Variable. Phase angle of the origin node of line l at period h.
$\theta to_{l,h}$	Variable. Phase angle of the destination node of line l at period h.
$FMax_{l}$	Parameter. Maximum flow of line l, i.e., from origin to destination.
$FMin_{l}$	Parameter. Minimum flow of line l, from destination to origin.

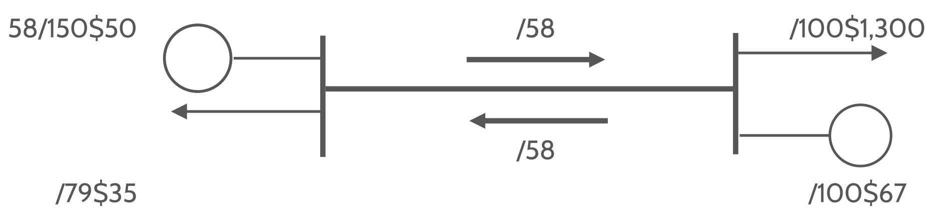
In a “conventional” economic dispatch, $PriceEGen_g$ represents the price of energy from a generator, calculated by considering the price of the fuel delivered to the plant (molecule and transport), the thermal regime, and the variable O&M costs.[33] It should be noted that this is the standard way of calculating the variable costs that enter as bids to the dispatch. Nevertheless, the algorithm is blind in this aspect, i.e., $PriceEGen_g$ is an input parameter to the algorithm and can represent variable generation costs, or, as in the case of the proposed reform to the Mexican Electricity Industry Law, it can represent total unit costs (variable costs plus energized fixed costs); for the algorithm itself, the source of this parameter is irrelevant.

1.2.1. Example – Two Dispatches

To clarify the abovementioned concepts, consider the system shown in Figure B. 1, which displays the purchase and sale offers/bids in the following format: **/X$Y** where **X** is the amount (MW) offered and **Y** is the minimum (sale) / maximum (purchase) price ($/MWh). For the transmission corridor **/Z**, where **Z** represents the maximum link flow, which in the example is equal in both directions.

Figure B. 2 shows the results of a conventional economic dispatch **R/**, where **R** is the dispatch result, next to the nodes is shown the nodal marginal price **$P**, where **P** is the Nodal Marginal Price (Local) in ($/MWh).

FIGURE B.1. Example system - purchase and sale offers/bids



Source: Compiled by the authors.

FIGURE B.2. Conventional economic dispatch

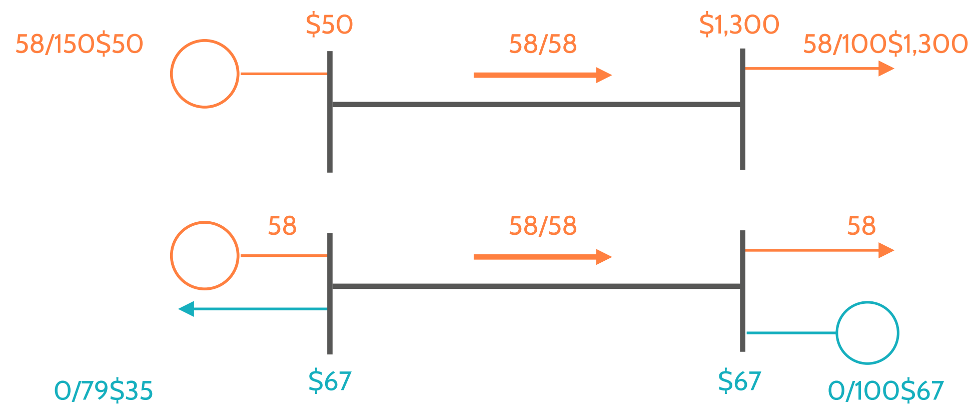
Source: Compiled by the authors.

[33] Operation and maintenance.

Now, if the bids shown in the upper part of Figure B. 1 are considered as belonging to Market 1, while those shown in the lower part are considered as those corresponding to Market 2, Figure B. 3 shows the solution to the application of two sequential dispatches, i.e. Market 1 is dispatched and the results shown in the upper part of this figure are obtained, the results of this dispatch are "frozen" and Market 2 is dispatched, whose results are shown in the lower part of the figure, whose results are shown in the lower part of Figure B. 3.

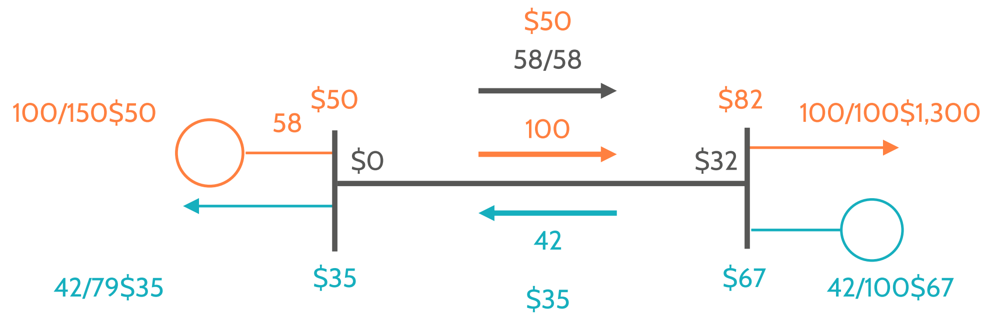
Finally, if both Markets 1 and 2 are co-optimized, the results are displayed in Figure B. 4.

FIGURE B.3. **Sequential dispatches**



Source: Compiled by the authors.

FIGURE B.4. **Co-optimized dispatches**



Source: Compiled by the authors.

To carry out the joint dispatch of both markets, in addition to including the nodal balancing equations considered in a conventional economic dispatch, it is necessary to include a balancing equation for each of the markets, i.e. each market must be balanced individually.

Figure B. 4 shows two prices at each node, one for each market, obtained from the LaGrange multipliers of the nodal balance equations and those corresponding to the balance equations of each market. Figure B. 4 shows that it does not make sense to dispatch Market 2 if considered in isolation, since the purchase bid shows a willingness to pay a maximum price of $35/MWh, while the selling offer shows a minimum price of $67/MWh; i.e., the supply and demand curves do not intersect, as shown in the lower part of Figure B. 3. However, in the joint dispatch of both markets, what Market 2 "loses": 42 MW at $(35-67)/MWh is more than offset by what it allows Market 1 to earn: 42 MW at $(1,300-50)/MWh and made possible by the "counterflow" caused by Market 2. The economic information of what Market 1 would gain from the dispatch of Market 2 is not transferred to Market 2 in the case of sequential dispatches.

There are, of course, more alternatives, e.g., three dispatches: the first one that co-optimizes both markets and from which only the MW are obtained, a second one that freezes the MW of Market 1 and dispatches Market 2 to obtain only the prices of Market 2, and a third dispatch that fixes the MW of Market 2 obtained in the first dispatch and dispatches Market 1 to obtain only the prices of Market 1. Exploring the implications of these alternatives goes beyond the basic objectives of this note, the intention of the examples shown is only to emphasize the importance of carrying out thorough analyses of the implications of the proposals before deciding to change marginalist market schemes.

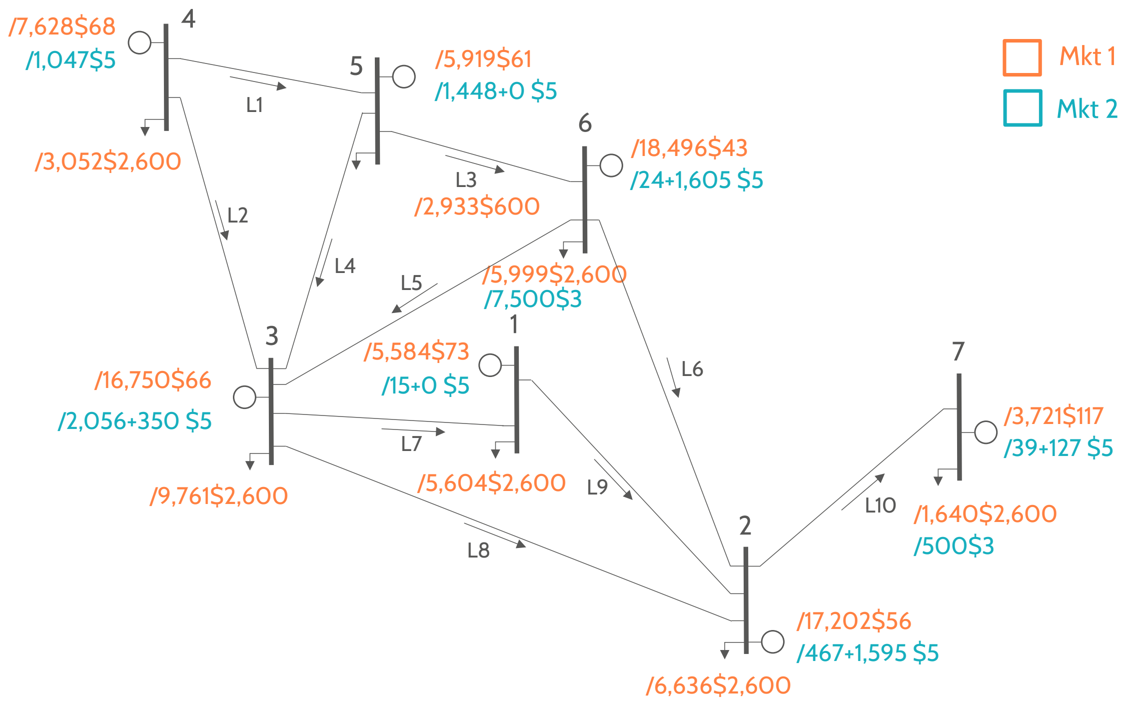
As discussed above, if the nodal prices shown in Figure B.4 are applied, Market 2 will have a deficit: 42*35 – 42*67 = 42*(35-67) = - 1,344; on the other hand, Market 1 will have a surplus of: 100*(82 – 50) = + 3,200.

Given that each of the Markets (1 and 2) is balanced, i.e., for each Market, the sum of the nodal injections is equal to the sum of the nodal withdrawals, an alternative interpretation of the co-optimized dispatch results is to consider that the solution is the product of an auction of financial transmission rights. Thus, Market 1 pays 3,200 for its total congestion impact, while Market 2 receives 1,344, which is just the imbalance from the simple application of nodal marginal prices.

Figure B. 5 shows the one-line diagram of a test system with several nested loops, as well as the purchase/sale bids/offers of two markets, one in which conventional technologies predominate—shown in red—, and the other for renewable technologies—shown in blue—(wind and solar photovoltaic).

Table B. 1, Table B. 2 and Table B. 3 show the results of the co-optimized dispatch of the two markets.

FIGURE B.5. **Test system. Purchase/sale bids/offers**



Source: Compiled by the authors.

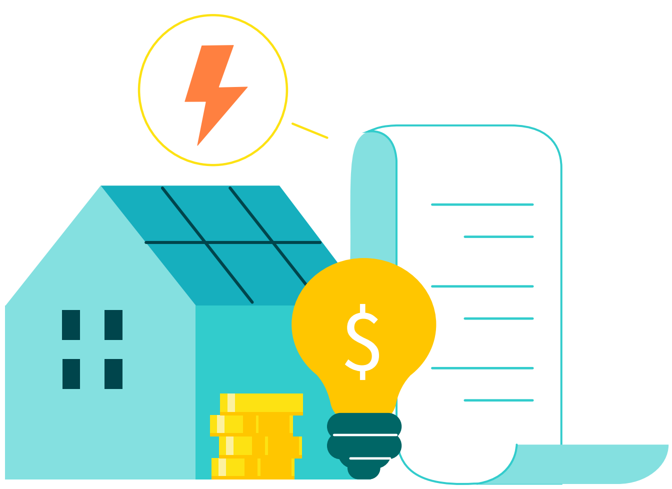


TABLE B.1. **Generation levels and payments to LMP from markets Mkt1 and Mkt2**

	Pg (MW)	Pgmax (MW)	PriceOffer (US$/MWh)	PmlGen (US$/MWh)	PagoGen (UUS$)	Subtotal (US$)
G1Mkt1	-	5,584	73	66	-	
G2Mkt1	11,257	17,202	56	56	630,387	
G3Mkt1	3,775	16,750	66	66	249,148	
G4Mkt1	790	7,628	68	68	53,701	
G5Mkt1	1,423	5,919	61	61	86,814	
G6Mkt1	17,756	18,496	43	43	763,503	
G7Mkt1	324	3,721	117	117	37,951	1,821,504
G1PV	15	15	5	26	400	
G2PV	467	467	5	16	7,466	
G3PV	2,056	2,056	5	26	53,458	
G4PV	1,047	1,047	5	28	29,319	
G5PV	1,488	1,488	5	21	31,253	
G6PV	-	24	5	3	-	
G7PV	39	39	5	77	3,033	
G1Wind	-	-	5	26	-	
G2Wind	1,595	1,595	5	16	25,515	
G3Wind	350	350	5	26	9,094	
G4Wind	2	2	5	28	58	
G5Wind	-	-	5	21	-	
G6Wind	-	1,605	5	3	-	
G7Wind	127	127	5	77	9,744	169,339

Source: Compiled by the authors.

TABLE B.2. **Demand levels and payments to LMP from markets Mkt1 and Mkt2**

	Pd (MW)	Pdmax (MW)	DemOffer (US$/MWh)	PmlDem (US$/MWh)	CobroDem (US$)	Subtotal (US$)
DN1Mkt1	5,604	5,604	2,600	66	371,500	
DN2Mkt1	6,336	6,336	2,600	56	354,817	
DN3Mkt1	9,761	9,761	2,600	66	644,207	
DN4Mkt1	3,052	3,052	2,600	68	207,540	
DN5Mkt1	2,933	2,933	2,600	61	178,896	
DN6Mkt1	5,999	5,999	2,600	43	257,955	
DN7Mkt1	1,640	1,640	2,600	117	191,915	2,206,830
DN1Mkt2	-	-	2,600	26	-	
DN2Mkt2	-	-	2,600	16	-	
DN3Mkt2	-	-	2,600	26	-	
DN4Mkt2	-	-	2,600	28	-	
DN5Mkt2	-	-	2,600	21	-	
DN6Mkt2	7,186	7,500	3	3	21,557	
DN7Mkt2	-	500	3	77	-	21,557

Source: Compiled by the authors.

TABLE B.3. Flows

	FlowMin (MW)	FlowMax (MW)	Flow (MW)	Miu T (US$/MW)	Abs(F)*MiuT(US$)
L1	-750	750	-750	9	6,498
L2	-1050	1050	-463	0	-
L3	-800	800	-800	19	15,192
L4	-200	200	29	0	-
L5	-3700	3700	3700	23	85,770
L6	-1000	1000	71	0	-
L7	-3550	3550	-161	0	-
L8	-350	350	-153	0	-
L9	-5750	5750	-5750	10	59,934
L10	-1150	1150	1150	61	70,150
				Total	237,543

Source: Compiled by the authors.

TABLE B.4. Balance of the markets Mkt1 and Mkt2

	Pago Dem (US$)	Pago Gen (US$)	Balance (US$)
Mkt1	2,206,8230	1,821,504	385,325
Mkt2	21,557	169,339	-147,782
Total	2,228,387	1,990,843	237,543

Source: Compiled by the authors.

The total balance of the markets is shown in Table B. 4.

Although Mkt2 balance is negative, the overall balance is positive; the amount is obtained from valuing purchases and sales at Nodal Marginal Prices, noting that, unlike a conventional dispatch, now there are two sets of marginal prices. It is also important to note that the total net balance corresponds to the Variable Transmission Revenues, obtained as shown in the following equation (11).

(11)

$$IVT = \sum_{l} |\mu_l| \cdot |Flujo_l|$$

Another perspective of the problem can be analyzed from the point of view of congestion. To this end, the impact of each of the markets on each of the transmission lines was calculated, as shown in Table B. 5 and Table B. 6.

Table B. 5 shows the sensitivities of transmission line flows to nodal injections, compensated at the slack node (compensating node); in this example, node N1 is selected as the slack node. Thus, for example, if 1 MW is injected at Node N7 and compensated by an extraction of 1 MW at Node N1, it will flow through line L10 (in reverse to the conventional flow, which goes from N2 to N7). A 1 MW injection at node N4, offset by an extraction at node N1, will be "split" between lines L1 and L2, 36.26% will flow through L1 and 63.74% through L2.

TABLE B.5. Impact of an injection at node *i* on the flow of line *l*

Line/node	N2	N3	N4	N5	N6	N7
L1	-0,0006	0,0012	0,3626	-0,3367	-0,0677	-0,0006
L2	0,0006	-0,0012	0,6374	0,3367	0,0677	0,0006
L3	-0,0007	0,0016	0,3027	0,5533	-0,0899	-0,0007
L4	0,0002	-0,0004	0,0599	0,1100	0,0221	0,0002
L5	0,0072	-0,0154	0,2761	0,5186	0,8640	0,0072
L6	-0,0079	0,0170	0,0266	0,0347	0,0462	-0,0079
L7	0,0306	0,9342	0,9253	0,9178	0,9072	0,0306
L8	-0,0227	0,0488	0,0481	0,0475	0,0467	-0,0227
L9	-0,9694	-0,0658	-0,0747	-0,0822	-0,0928	-0,9694
L10						-1

Source: Compiled by the authors.

Using the sensitivities shown in Table B. 5, also known as PTDF (Power Transfer Distribution Factors or Dfaxes) and the net injections of each of the markets, Table B. 6 shows the impact of each market on each transmission line.

TABLE B.6. Physical impact of markets on transmission lines

l	Mkt1	Mkt2	Total (MW)
L1	-1,118	368	-750
L2	-1,145	681	-463
L3	-2,589	1,789	-800
L4	-38	67	29
L5	8,868	-5,168	3,700
L6	300	-229	71
L7	1,705	-1,866	-161
L8	-6	-147	-153
L9	-3,899	-1,851	-5,750
L10	1,316	-166	1,150

Source: Compiled by the authors.

As we can see, the total impact corresponds to the solution of the co-optimized dispatch of both markets.

The economic impact of each of the markets can be calculated by multiplying the physical impact of each market on each line, shown in Table B. 6, by the "value" of each line, given by the LaGrange Multiplier of the transmission lines, shown in Table B. 3. The result is shown in Table B. 7, which matches those shown in Table B. 3 and Table B. 4.

TABLE B.7. Economic impact of the markets on transmission lines

l	Mkt1	Mkt2	Total ($)
L1	9,685	-3,187	6,498
L3	49,166	-33,975	15,192
L5	205,562	-119,792	85,770
L9	40,641	19,293	59,934
L10	80,272	-10,122	70,150
Total	385,325	-147,782	237,543

Source: Compiled by the authors.

It should be noted that if we were to apply "pure" LMPs, i.e., the LaGrange Multipliers of the nodal balance equations to all the injections and withdrawals of both markets, i.e., without "deforming" them with the LaGrange Multipliers of the global balance equation of each of the markets, the financial balance would be the same for each market, since adding the LaGrange Multipliers of the balance of each market to the pure LMPs increases/decreases each LMP by the same amount, i.e., all the generators are paid for said increase, but this is compensated in the same amount by the increment charged to all demands.

Finally, it should be noted that the ideas outlined in this Annex can be applied to any number of markets (*nm*) and that one of the equations of the global market balance is redundant since this balance is automatically satisfied.

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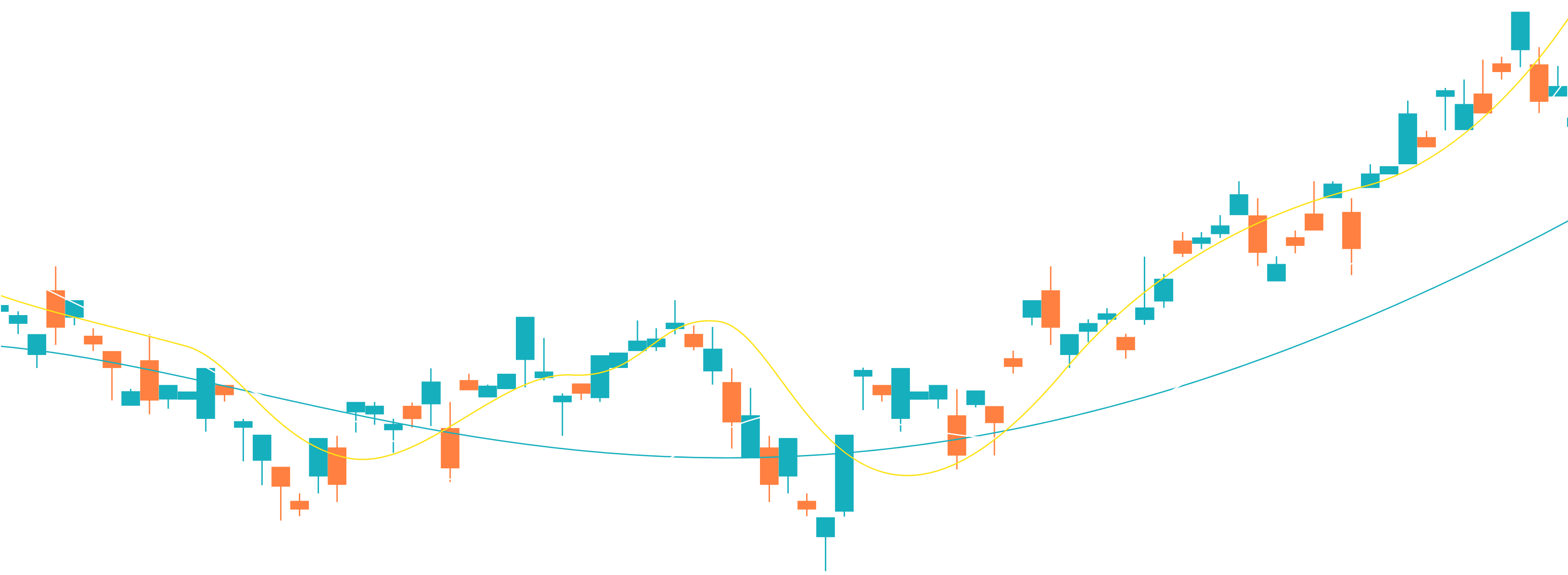

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