Pontifícia Universidade Católica
do Rio de Janeiro

Luiza Bastos Ribeiro

Technical and economical aspects of WEMs: an international comparison and main contributions for improvements in Brazil

Dissertação de Mestrado

Dissertation presented to the Programa de Pós–graduação em Engenharia Elétrica of PUC-Rio in partial fulfillment of the requirements for the degree of Mestre em Engenharia Elétrica.

Advisor : Prof. Alexandre Street de Aguiar
Co-advisor: Prof. Davi Michel Valladão

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Abstract

Bastos Ribeiro, Luiza; Street, Alexandre (Advisor); Valladão, Davi Michel (Co-Advisor). **Technical and economical aspects of WEMs: an international comparison and main contributions for improvements in Brazil**. Rio de Janeiro, 2021. 70p. Dissertação de Mestrado – Departamento de , Pontifícia Universidade Católica do Rio de Janeiro.

The Brazilian power-market design features were decided based on the system's physical and economic characteristics observed in the '90s, when the system was remarkably hydro-dominated and the economy experienced large GDP growth rates. Nowadays, the power system's capacity is still hydro-dominated, albeit with a significantly lower hydro participation (64%), has experienced a sharp growth in variable renewable energy integration, and has faced the impacts of different economic crises. Therefore, some of the approximations and assumptions adopted for the regulatory framework based on the original system's condition and economic reality are not valid anymore. Failing to adapt the regulatory framework to the current system and economic realities may provide poor market signals, possibly threatening the long-run system sustainability. Based on the continued flaws experienced in this country, the need for a market-design review is critical and urgent in Brazil. The public consultation named CP 33 proposed a handful agenda for the Brazilian power sector modernization, which is the backbone of some bills already in progress. Despite the consensus on the modernization agenda, especially on a more short-term-based market-oriented approach, there are still many concerns and questions on which market features should be adopted. The vast literature and international experience in the subject notwithstanding, each system's particularities, challenge any simplistic attempt to match the Brazilian case with previously reported experiences. Thus, this work aims to 1) define a general market design nomenclature and classify relevant market structures, 2) draw a systematized panorama of the physical characteristics that have influenced the selection of different market designs and mechanisms in other similar markets, and 3) compare the Brazilian market design, within a common language using 1) and 2), to the international experience. Markets from South and North America, Europe, and New Zealand were selected to present comparisons between them and Brazil. Based on that, we contribute with an updated and standardized panorama of a few relevant market designs and structures. Additionally, we raise awareness and discuss the relevant lessons

learned from the international experience applicable to support and foster the Brazilian market modernization agenda.

Keywords

Wholesale Electricity Market; Market Desig.

Resumo

Bastos Ribeiro, Luiza; Street, Alexandre; Valladão, Davi Michel. **Características técnicas e econômicas dos mercados atacadistas de energia: Uma comparação internacional e principais contribuições para o mercado Brasileiro**. Rio de Janeiro, 2021. 70p. Dissertação de Mestrado – Departamento de , Pontifícia Universidade Católica do Rio de Janeiro.

O mercado de energia do Brasileiro foi decidido com base nas suas características físicas dos anos 90, predominantemente hídrico. Apesar de ainda dominado pela geração hidrelétrica, a participação dessa fonte foi reduzida significativamente, cedendo espaço principalmente para as fontes renováveis intermitentes. Sendo assim, há uma dissonância entre o atual sistema elétrico e aquele que embasou a atual regulação. As hipóteses e aproximações adotadas para a constituição da estrutura regulatória foram baseadas em um sistema com excesso de flexibilidade e alta previsibilidade no curto prazo. A maior participação das renováveis intermitentes, e sua projeção de crescimento nos próximos anos faz com essa estrutura se torne cada vez menos aderente e suas falhas intensificadas. A falta de adaptação pode enfraquecer os sinais econômicos e ameaçar a sustentabilidade e adequabilidade do sistema no longo prazo. A consulta pública CP 33 propôs uma agenda pragmática para auxiliar no processo de modernização do setor, se tornando um dos pilares principais de leis em tramitação no Congresso sobre esse assunto. Apesar do consenso a respeito da necessidade de modernização, principalmente na adoção de um mercado de curto prazo mais competitivo, ainda existem muitas preocupações e questionamentos a respeito dos mecanismos de mercados a serem adotados. A vasta literatura e as experiências internacionais podem auxiliar muito no processo de modernização nacional. Todavia, as particularidades de cada sistema, como matriz de geração e dimensões territoriais, desafiam qualquer tentativa simplista de compatibilizar o caso Brasileiro com experiências relatadas. Dessa maneira, esse trabalho tem como objetivo 1) definir uma nomenclatura e classificar as estruturas de mercado relevantes, 2) delinear um panorama sistematizado das características que influenciaram a escolha de diferentes mecanismos de mercado 3) comparar os mercados internacionais ao mercado Brasileiro utilizando as nomenclaturas e as características físicas definidas em 1) e 2). Mercados da América do Sul e do Norte, Europa e Nova Zelândia foram selecionados para apresentar as análises comparativas. Dessa maneira, nós contribuímos com um panorama atualizado e padronizado de alguns desenhos mercados internacionais e mecanismos relevantes. Além do mais, nós conscientizamos e discutimos lições relevantes aprendidas com a experiência internacional para apoiar e fomentar a agenda de modernização do mercado Brasileiro.

Palavras-chave

Design de Mercado; Mercados maioristas de Energia.

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1
Introduction

The electricity sector deregulation worldwide started in the 20th century. Motivated by the managerial failures of the public administration to provide innovative solutions in crisis times, the need to attract private capital to react against the exhaustion of the economy of scale model supported by vertically-integrated state-owned firms, and the desire to achieve efficiency fostered the belief in the market ideal (laissez-faire ideology). Due to the wide range of system characteristics, the deregulation process led to a myriad of market designs. For example, several European countries, inspired by the laissez-faire ideology, adopted a market approach closer to any other commodity trading. On the other hand, the US adopted a more centralized-based market approach. Finally, Brazil and other Latin American electricity markets, remarkably hydro-dominated, opted for even more centralized approaches in the short-term, with audited-cost-based offers and centralized assessments for the opportunity cost of water.

Brazil started its first electricity reform in 1996, aiming at incentivizing private investment in electricity supply, create competitiveness in the generation and trading sectors, and reduce investment risks. Nevertheless, the reform did not expand the generation fleet as rapidly as expected, incurring a severe supply crisis in 2001 and 2002. The rationing allied with the political scenario changes implied a second sector reform in 2004, which has been updated since then but that still constitutes the main current market framework. The 2004 reform inherited some previous features and included new ones resulting in a market with: competition restricted to the wholesale environment, a cost-based dispatch, *ex-ante* “real-time" prices based on costs (absence of short-term markets *strictu-sensu*), a mandatory energy reallocation mechanism aiming to mitigate individual hydroelectric price and quantity risk, and energy and reliability bundled as one product. The three main guidelines of this reform aimed at ensuring long-term supply adequacy [1] according to the following logic: 1) All demand must be 100% backed on contracts, 2) all contracts must be backed by physical generation capacity, 3) distribution companies can only buy contracts through publicly open auctions. This resulted in a division of the market in regulated and non-regulated (where contracts could be freely and bilaterally negotiated). Despite of this division, all contracts, traded in both markets, were conceived as bundled products encompassing energy and energetic reliability products at the same time.

At the time of the second reform, the Brazilian installed capacity consisted of approximately 77% hydro, 22% thermal, and 1% variable renewable energy (VRE). Additionally, the high average load-growth rate was compatible with emerging economies. In that context, implemented reforms showed suitability to the system's physical characteristics as further related [2]. After the 2001 crisis, a market-based approach was proposed, but the discussion was postponed for the future reform that was supposed to happen in the next years. During the 2004 reforms, the significant changes in the contract market prevented this discussion to spotlight again. Additionally, at that time, the mandatory energy reallocation mechanism[1] was providing hydros with a smooth and low risk allocated-energy profile. Although this mechanism has played a relevant role during the 2004 transition, its flaws, that were still to be revealed in the subsequent decade, were covered by the excess of resources after the large energy efficiency induced by the 2001 rationing that structurally reduced the total system load in more than 20%. Moreover, because Brazil was not capacity-constrained due to the flexibility assured by the abundance of hydro generators, there was no need for capacity markets.

Due to the massive global production of renewable generators' equipment and the incentives promoted by the Brazilian government (e.g., exemption from tariffs for the use of the transmission and distribution system, the facilitated access to the non-regulated markets), the VREs have suffered a reduction in investment costs. Besides, the speedy implementation, lower environmental barriers, and the inexorable increase in demand have indicated the VRE as an excellent solution and promoted an accelerated growth of this type of generation in the Brazilian electricity matrix.

The features mentioned above associated with the mandatory forward contracting led to a substantial growth in the Brazilian installed capacity, bringing security of supply and the diversification of the generation fleet. The market attracted various technologies such as wind, solar, biomass, and

[1]The mandatory energy reallocation mechanism allocates to each centrally-dispatched hydroelectric unit a share of the total hydro generation based on the unit's firm generation certificates. This mechanisms was created to mitigate the risk a hydroelectric unit would face when participating in a centralized cost-based hydrothermal market, where the system operator chooses the generation of each unit disregarding their long-term contract agreements. To share this risk, the energy allocated by this mechanism replaces the physical generation on the short-term market settlements, where contracts and generation differences are cleared at the spot price. Because the total generation profile is much less volatile than the individual profiles, this mechanism was conceived to mitigate the individual risk but not the systemic risk.

thermal plants, resulting in an installed capacity of 64% hydro, 25% thermal, and 11% variable renewable energy in 2019 [3]. The most prominent capacity growth was the variable renewable energy (VRE), which increased its share by 10%, reducing the hydroelectric plants' relative participation. Although the technology diversification is in line with the global concerns on climate change, a higher amount of VRE and a decremented flexibility (provided by the hydro generators) create several complexities and challenges in the system's operation that the current market model is no longer capable of addressing. The cost-based dispatch allied with the MRE approach tends to under-compensate efficient resources due to the plants' impossibility of manifesting their risk-aversion and the socialization of the individual benefits. Additionally, the transmission constraints simplification in four zones for price disclosure, and its release one day-ahead is likely to reflect an operation unattached from what happens in real-time. Especially in a system with a growing share of VRE, many changes occur after the day-ahead, and they tend to create more transmission bottlenecks since they are located far from the load centers. Therefore, it is often necessary to call out-of-merit units to correct the unplanned deviation in real-time, which are compensated through tariffs, meaning that the prices fail to enclose many operational costs, culminating in price distortions and lack of transparency. Finally, the regulated auctions for the PPAs with long delivery periods create substantial market inertia related to accompanying the technology changes.

Given the perceived changes in the Brazilian resource matrix and the national concern on the market model exhaustion, the government, represented by its institutions, has taken initiatives to promote a market modernization. This initiative was considered as the third wave of electricity reform in Brazil. Among the relevant initiatives, we highlight, in particular, the public consultation (CP) nº 33/2017. The CP 33 provided a handful of agendas for the Brazilian power sector modernization with suggestions that follow a chronological order. Among other things, including enhancing the price signals, considering the preference on a bid-based market, the unbundling of reliability and energy as different products, and the gradual opening of the regulated market [4]. One of the already implemented improvements was the changing on dispatch and prices from a weekly frequency to a half-hourly dispatch and hourly prices, incorporating inter-temporal constraints [5]. Furthermore, many of the discussions proposed at CP 33 are incorporated in the bill in progress through PL 414/2021 and discussed on the modernization working group created through MME Ordinance Nº. 187 [6].

Despite the consensus on the modernization agenda, there are still many concerns and questions on which market features should be adopted. The vast literature and international experience in the subject notwithstanding, each system's particularities, such as the generation matrix, economic and social development, and territorial dimensions, challenge any simplistic attempt to match the Brazilian case with previously reported experiences. Also, analyzing the different existent market approaches is often hindered due to the lack of standardization on their definitions, the constant modernization around the globe, and the practice in which details about market design are embedded in a multitude of manuals on various websites of system operators.

Similar works with international electricity market comparison were encountered in [7], that defines the typical market structures in Europe, such as dispatch, settlement, pricing mechanisms, capacity payments, and congestion management, and analyzes a set of specific markets (UK, Spain, and Nord Pool). [8] compare European with North American markets, assuming their general characteristics such as dispatch market model, types of bilateral trading, and the presence of congestion management instruments. In [9], they investigate the day-ahead markets' different pricing and bid mechanisms from the USA and Europe, detailing the mechanisms behind each organizational market format and outlining their good practices, but disregarding their specificities. [10] make a detailed analysis regarding the different capacity markets current in the USA. Similarly, [11] selected a set of North American markets to contrast the different capacity markets relating to their efficiency in incentivizing performance and achieving cost-effective policies in an environment with higher VRE participation. [12] developed a historical analysis of the supply adequacy mechanisms in the Latin American markets, drawing a critical assessment of changes in those market structures. In [13] they presented a comparative analysis of ancillary services on the markets of the UK, the Nordics, California, Argentina, Australia, and Spain, comparing the services of voltage control, frequency regulation, and system restoration. To the authors' knowledge, the papers on this matter either compare general features from different regions such as Europe and North America or chose a specific topic like capacity market and ancillary services to compare the markets individually in a more detailed manner. Furthermore, the less developed markets, such as Latin American, were generally set aside in comparison or examined jointly with other less developed markets. In this context, the thrust of this work is:

1. To define a general market design nomenclature that encompasses markets from different levels of maturity and allows an individual analysis and classification of relevant market structures.

2. To draw a systematized panorama of the physical characteristics that have influenced the selection of different market designs and mechanisms in other similar markets. In this topic, we intend to justify the adopted market models according to their physical aspects, which will further help correlate the existing mechanisms to the Brazilian's or to indicate suitable mechanisms to be adopted.

3. To compare the Brazilian market design, within a common language using topics 1 and 2, to the international experience. Markets from Chile, Mexico, Colombia, Ontario, New Zealand, PJM, CAISO, the Nordics, MIBEL, Germany, and United Kingdom were selected to present comparisons between them and Brazil. Based on that, we contribute with an updated and standardized panorama of a few relevant market designs and structures. Additionally, we raise awareness and discuss the relevant lessons learned from the international experience applicable to support and foster the Brazilian market modernization agenda.

We structure the rest of this work as follows. First, the nomenclature and typology adopted to classify the markets are described in Section 2. Section 3 covers an overview of the systems' physical aspects that justifies different market approaches. Section 4 promotes a discussion and gives recommendations based on the similarities founded in Section 3 vis-a-vis with what exists of guidelines for the future paths in Brazil, based on CP 33 and its respective proposed bills. Finally, conclusions of this study are drawn in Section 6.

2
Nomenclature - General aspects of wholesale electricity markets

This chapter aims to introduce the market structures using a standardized language that allows the comparison of different international markets. It is essential to highlight that the features presented are design elements that can be used, but each market is organized differently, with different features combined further detailed.

First, one can distinguish between physical and financial markets. It is possible to find different definitions of physical contracts depending on the market. Hence, to avoid misunderstanding, the definitions adopted of both physical and financial contracts are given below:

- **Physical or Deliverable products:** it can be described as the contracts in which the settlement is based on the balancing between supply and demand (electricity traded is going to be produced and delivered). With a physical contract, a generator commits to provide a certain amount of electricity [14].
- **Financial products:** the contracts between traders as agreements that give certainty to both parts. The delivery is purely financial based on an electricity reference price [14].

Second, electricity markets are multi-commodity markets, including at least energy and ancillary services. Third, electricity can be traded over-the-counter (OTC) or at exchanges. The OTC negotiations consist of bilateral agreements that may be concluded either over the phone or through an internet-based broker platform. Third, the organized trading venues may be present in different time scales of the market, and they can adopt different structures relating to their clearing process and pricing mechanisms. In order to classify the wholesale markets' different organizational forms, we will first define the nomenclature adopted in the three market layers.

2.1
Pools

The pool comprises organized trading environments (the short-term electricity markets) managed by an entity called the market operator. They can be bid-based or cost-based and are employed to guarantee a price and a dispatch plan for electricity for a short period in advance and allow fine-tuning transactions. In the cost-based pool, the participants are limited to declare their audited costs, while in the bid-based pool, the agents are free to express their opportunity costs to adjust the positions previously agreed in the mid/long-term markets [15]. In practice, the pools are found in many different combinations of features. Thus, in the next sections, we explain the most common features and their possible arrangements.

2.1.1
Energy short-term markets

The cost-based pools cannot be defined as markets *strictu-senso* since it does not reveal a competitive-driven price. However, since their organized trading environments work in a very similar way (differentiating in the offer modality: audited or opportunity cost), and it is customary to find cost-based pools calling their trading environment as short-term markets (see [16]), we will refer to these environments for both cases as short-term markets. Thus, the pools can include three different market places [17, 15]:

- Day-ahead market (DAM): a market where both scheduling and clearing prices are evaluated for each hour or a proportion of an hour of the following operating day, based, in general, on generation offers (or audited costs) and demand bids (when allowed).
- Intraday market (IDM): begins after day-ahead market clears and ends closer to actual system operation. These markets are encountered in two forms: continuous and auctions. The auction form is similar to the day ahead, with a uniform clearing price for each time frame. The continuous form works as a first-come-first-served market where the contracts are negotiated through an electronic platform. The participants have updated offers at all times on the platform, and they have to “hit” the orders they are willing to buy or sell at the specified price.
- Real-time market (RTM): also called balancing markets, it is the last market before power delivery. It happens in an auction form and allows last-minute imbalances adjustments to cover either a generation excess or deficit.

When demand is allowed to bid, the pool is called two-sided; otherwise, it is called a one-sided pool.

2.1.2 Reserve and regulation markets

Besides relying on energy, the system operator responsible for the technical operation, maintenance, and expanding the grid, may also need to acquire ancillary services to keep reliability. In general terms, ancillary services can be defined as the resources and actions that ensure the security and quality of the power system's supply needs. The ancillary services products may vary according to the system necessities. They are usually divided into three main groups: frequency control, coordination and operation, and system backup and restoration. This work will focus on the frequency control group since they are the ancillary services subset usually procured through market-based mechanisms [13].

The frequency control services are related to the additional capacities (generation and responsive load availability) available to system operators to address any power balance mismatch. The resources available to accomplish this service needs must respond fast and be available either online or on-standby so that they can be called on to assist if load increases or generation decreases, or vice-versa (load decreases and generation increases). Depending on the time response, the resources can be separated into two categories, the Frequency Regulation, and the Operational Reserves. The first one includes the generation resources capable of providing a generation capacity of autonomous response (typically governors and Automatic Generation Control - AGC) to keep the balance continuously. The second one includes the resources (generators and demand response) to keep track of longer load variations due to unexpected events. Usually, both frequency regulation and reserves are distinguished by different types depending on their accessibility speed [18]. Both products can be procured either jointly to energy in the short-term markets, in a single multi-product auction, or a separate auction immediately after the day-ahead market [18].

In some structures like most North-American markets, the system operator also develops market operator function and administers all short-term markets for energy and ancillary services. On the other hand, it is also common to encounter markets such as the European, where the system operator administers only the reserve and the balancing markets while a different market operator (named power exchanges) runs the short-term energy markets [18]. Depending on these markets' governance, the market-clearing procedure, and the type of contracts, we classify the market organization differently, as we will further detail.

2.1.3
Market-clearing, pricing, and settlement

The electricity pool's marketplaces work similarly: the market operator collects bids or audited costs and clears the market using a market-clearing procedure. Besides resulting in market-clearing prices, it determines the generation and consumption schedules for the physical operation.

The physical electricity operation is much more complex than any other commodity due to its intrinsic characteristics: it is governed by physical laws that hinder the flow control, demand can purchase energy regardless of having a contract, and its elasticity is typically low. Also, there are inefficient and low storage capability, the suppliers have technical constraints, and the balance must be kept at all times. Therefore, unlike other commodities' clearing processes, electricity needs some assumptions relating to the system operational reality to ensure that the schedules are physically possible and guarantee a certain level of reliability [19].

The market-clearing process will be categorized in the following items concerning the model's assumptions for the particular electricity commodities traded in the pool. First of all, the market-clearing process can be divided due to the suppliers' internalization of the model's technical limitations. There are two approaches considered in this work:

- Multi-part bid (cost) model: the suppliers must inform their audited costs or bids, including price-quantity and other components such as lumpy-costs (start-up and shut-down costs) and technical constraints (e.g., ramp rates). The clearing approach is the straightforward application of the Security Constrained Unit Commitment and/or Economic Dispatch optimization models. The objective is to meet the system demand with maximum social welfare while satisfying a set of constraints of different natures as, for instance, network and producer operational restrictions (each wholesale market chooses the degree of complexity of their models) [20];
- Complex bid model: in this model, the market operator receives simple bids (price-quantity for each time frame of the operative day) or complex bids (e.g., block bids: price-quantity for a block of time frames; accepted or rejected entirely). In this framework, the clearing process could include the physical limitation of transmission networks, but the suppliers' responsibility is to incorporate their limitations in their bids and recover

their fixed costs. The objective is also to maximize social welfare, but the only constraint is to respect the transmission capacity limits [17].

In both multi-part and complex bid (cost) models, the prices are given by the variable cost of the marginal unit scheduled. Mathematically, this could be achieved by the dual variable of the balance constraints between demand and generation at every time and location considered in the model or by just taking the marginal non-constrained unit running without enclosing inter-temporal constraints.

The clearing procedure can also differ according to its spatial granularity. That is if it takes into account the physical limits of the transmission network. There are two ways of incorporating the transmission grid in the clearing method [20]:

- Zonal-pricing model: includes network constraints in a simplified manner, just taking into account clusters of nodes. When just one zone is considered for the entire system, the clearing method is called single-pricing model [1]. The zonal prices may be the output from a physically aggregated network, i.e., the original network is replaced by a simplified one, or from an is economic aggregation, which considers the original network in the dispatch model and then aggregates the prices into zones.
- Nodal-pricing model: energy prices properly reflect transmission constraints, equal to the marginal value of energy at each stage and grid location. Consequently, nodal prices implicitly include transmission congestion, integrating this effect into a single monetary value. When the prices between nodes are different, they are affected by the binding transmission constraints.

The differences in prices between nodes or zones are called congestion costs. Finally, there are usually two settlement structures according to the presence of short-term markets [21]:

- Single-settlement model: comprises only one short-term market, and it is a single shot. That is, all short-term transactions are settled with this market price and metered generation and consumption.
- Multi-settlement model: there are at least two short-term markets (DAM and RTM). In these environments, the agents can make commits in the previous markets, which are financially settled, and as uncertainty

[1] The network constraints are ignored for pricing purposes, hence incurring a single price for the entire system.

decreases, they can adjust their positions on the following markets. Finally, if there is any imbalance in real-time, the difference between committed quantity and metered is cleared at the real-time price.

The day-ahead and intra-day markets are both cleared before the real operation, and hence, the prices are *ex-ante*. At the real-time market, the prices can be released either *ex-ante*, from the dispatch instruction or *ex-post* considering metered demand. The more *ex-ante* the price is calculated, the less realistic it tends to be due to forecasting errors.

2.1.4 Market pools organization

We could name two different organizational structures concerning the system operator participation and the clearing model adopted: The integrated and the unbundled pools. The features of the structures are [19]:

– Integrated pool: it can be a single-settlement or multi-settlement, adopts a multi-part bid (cost) clearing model for the short-term energy market with a system operator responsible for all short-term electricity markets. When they present either day-ahead or day-ahead and intraday markets, they are financial markets, which means that the instructions will not necessarily happen but are financially settled. This structure is usually found in the North American markets, and it is usually described as the engineers' markets due to the complex optimization model incorporated in the clearing process.

– Unbundled pool: a multi-settlement market with a complex bid model for both day-ahead and intraday markets, run by one or more independent market operators called power exchanges (PXs). The power exchanges such as Nordpool and OMIE are voluntary environments for trading physically and financially binding contracts. The participants notify their physical contracts (agreed either in the power exchange or OTC) to the system operator, which at some point in time takes over to ensure the system reliability. When the "gate" into the physical contract market closes, all further adjustments are addressed by trading with the system operator into the balance or reserve markets. Hence, the unbundled pool works with the system operator's limited participation, netting the imbalances and keeping the system secure while supply and demand must meet elsewhere, either bilaterally or in the power exchange. This structure is usually found in the European markets usually defined as the economists' market, since its clearing model "simplicity" tries to approximate the other commodities trading markets.

Gathering the concepts introduced above, we defined five groups to accommodate the different markets as illustrated in Figure 2.1.

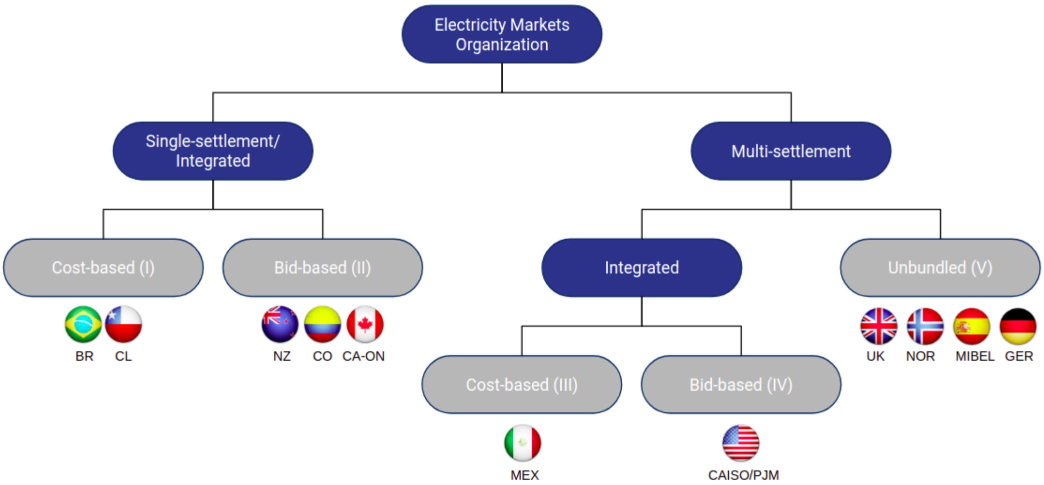

Figure 2.1: Market Organization

The integrated markets can incorporate a decentralization level allowing physical and financial agreements. When the physical agreements are considered, the generators must report their contracts to the SO at the day-ahead market. The SO receives both the schedules from the physical contracts (which work as minimum generation) and bids from traders who are willing to modify scheduled positions or provide imbalances. The SO runs its optimization software, including all information, and accepts only viable commitments (the ones that accomplish the optimization model's physical constraints), and the SO remains responsible for clearing the "residual" differences that resulted from the agreements [22].

The unbundled markets can have more than one power exchange operating in the market, and their short-term markets are usually coupled to other countries. Furthermore, both integrated and unbundled markets can still be different according to the details such as spatial granularity and time resolution of the clearing process, and its market-based products. Because they are not standardized, the specifics will be described in Sections 3 and 4 .

2.2 Long-term markets

Electricity pool prices are especially volatile when compared to other commodities. Generally, volatility can be due to the peculiar physical attributes of electricity production and distribution. Because power plants are capital-intensive, invest in an unpredictable environment would mean a substantial financial risk. Therefore, most electricity markets include the mid and long-term markets besides the short-term markets to foster new investment and keep reliability.

The long-term markets are the markets that enable the trading of a great variety of energy and energy-related products years to weeks in advance of delivery. They can be financial or physical instruments to hedge against energy price variability and unpredictability; to ensure resource adequacy; to hedge against transmission price risk, or accomplish ancillary services needs. The contracts derived from this market may be agreed upon over-the-counter or through exchanges. No matter the trading environment, all contracts share some characteristics: defined amount, price, location, and period. [23].

2.2.1 Hedge Mechanisms

The participants can trade energy in the forward market for hedging at both OTC or exchanges. The OTC markets provide greater flexibility because parties can customize their forward contracts as they please. On the other hand, the agents take longer to quote a fair price and are more exposed to credit risk since one of the counterparties may not deliver on his contract (e.g., in case of insolvency). The presence of internet-broker platforms in the OTC market may solve the slowness problem to quote prices, but the credit risk is inherent to this trading modality. Differently, the exchanges decrease the credit risk for the market participants, implementing a central counterparty clearing house (CCP), and offer faster negotiations on standard products (often called derivatives [2]). However, it may not comprise the variety of products that the market might need [14, 24].

The underlying prices of the electricity forward contracts are the short-term prices, usually called spot prices. They represent the final price of the physical commodity in the prevailing situation of supply and demand. Therefore, the derivatives markets are primarily driven by expectations regarding the future situation in short-term markets. On unbundled pools, the spot price usually refers to the day-ahead market price, while in the integrated, it can vary in between the short-term markets (day-ahead, intraday, or real-time) [24]. Here, the spot prices will be referred to the real-time prices.

As already stated, a market under nodal and zonal pricing model may have the marginal cost of electricity varying from one zone (or node) to another.

[2] Like other commodities, the exchanges usually offer Futures, Options, and Swaps.

In these trading environments, an agent with a forward contract in energy is not perfectly hedged since it is exposed to the congestion costs. Hence, it is common to find financial products to allocate transmission rights and allow participants to hedge against locational price differences. Some markets accomplish that with the Financial Transmission Rights (FTRs), which are contracts between a market participant and the system operator, where the holder of the FTR receives (or pays) the difference between prices at two locations (FTRs are usually settled on the DAM prices). FTRs include other advantages such as the provision of revenue sufficiency for contracts for differences, the redistribution of the congestion revenue that the system operator collects, and the provision of price signals for transmission and generation investors. The FTR allocation mechanisms are usually auction processes run by a SO, limiting the overall amount of FTRs that can be physically issued [25].

2.2.2 Resource Adequacy Mechanisms

Ideally, the transparent prices from the short-term markets allied with liquid forward markets would be sufficient to guarantee the security of supply. Whenever the demand suppliers projected an increase in consumption and a concomitant short of supply (which implies higher prices), it would voluntarily establish forward and(or) future contracts with the generators to hedge against the forecast prices. The contracts would also facilitate the utility's financing and fixed costs coverage. However, the several inefficiencies of the electricity market make it very incomplete and imperfectly competitive. One particular major problem is what [26] termed as the "reliability externality", and it is related to the low demand flexibility. The retail customers generally do not have access to real-time prices, hence having no reason to respond. Also, most demand cannot respond or cannot respond quickly enough to the prices, making overall demand very price-inelastic. The market-clearing prices are affected by price-inelastic demand since, at scarcity moments, it could be no equilibrium price or very high prices. Thus, to avoid market power, the market operator commonly limits the suppliers' offer price or the maximum market-clearing price at short moments. The price caps also limit the demand "penalty" for not being covered in contracts [27].

The lower the price caps, the more consumers rely only on short-term markets. That is, the forward price a generator would be willing to agree (at minimum, its average total cost of supplying that energy) could be higher than the expected spot prices, depending on the cap. Therefore, it would be more profitable for the consumer to purchase energy in the short-term market instead of the forward agreement. The lower procurement in the forward markets could increase the probability of insufficient supply, hindering the system operator's ability to ensure reliability, making the system more susceptible to blackouts. Since blackouts are equally likely to happen to any consumer regardless of their energy forward contracts, all consumers have an incentive to under-procure their expected energy needs in the forward market (also known as the free-rider problem). Additionally, the price cap would undermine the peaker generators to recover their fixed costs by being set too low. Therefore, the price caps and limited forward agreements reduce the generators' revenue, which creates both the missing money and the missing market problems inhibiting new generation plants from being financed and built [28, 26].

Therefore, many markets use a regulatory intervention to assure firmness and adequacy of supply, the resource adequacy mechanisms. The Resource Adequacy Mechanism (RAM) is a complimentary service that pays for the units' availability without necessarily generating energy. It attempts to reduce some flaws inherent to electricity markets and guarantee investment in electricity generation capacity to meet the projected peak demand. Although each market has its own rules, in general, they have some characteristics in common such as [29]:

- Demand is defined on a regulatory basis. The regulator or the system operator specifies the amount of capacity needed to supply the forecast load with enough margin to allow for necessary operating reserves due to uncertainties;
- Each resource is assigned a reliability credit value, which defines the amount of reliability it can sell. This value is also regulated, and it is the energy deliverable in a stressful situation (e.g., high demand and low renewable generation);
- All contracted generators receive a fixed payment in exchange for an availability or physical production during scarcity conditions;

The system's physical configuration impacts on what the system is most constrained, which usually defines the reliability criteria adopted. Generally, the system operator may contract firm energy or capacity. Firm energy is the ability to produce energy during a dry period, commonly adopted in hydro-dominate systems. Capacity is the ability to be available in an emergency condition throughout a delivery period, commonly adopted in systems with a lack of flexibility.

A reliability payment remunerates the resources that provide either firm-energy or capacity and can be classified as price or quantity based. The price-based mechanisms consist of rewarding every supplier of reliability through a target price, which is calculated to induce the new generation's right quantity. On the other hand, the quantity-based approach's basic principle is to set a target quantity resulting in a market-driven price. Both categories can also be subdivided into market-wide and targeted approaches. Whereas market-wide mechanisms remunerate all reliability resources, target mechanisms support a selected group of generating resources or technologies. More specifically, five different types of mechanisms can be differentiated accordingly to the Agency of Energy Regulators [30]:

- Strategic Reserves: a certain amount of additional capacity, defined by the operator, is contracted and held in reserve outside the Electricity Market. That is, the strategic reserves suppliers do not participate in the spot price formation. The reserve capacity is only operated if specific conditions are met.
- Reliability Auction: the system operator defines the quantity of capacity/firm-energy and centrally procures it through auctions. The participants bid to receive financial support that should be sufficient to build the new capacity required. The reliability providers are also allowed to participate in the electricity market.
- Reliability Obligation: an obligation is placed on load-services entities and large consumers to contract an amount of capacity/firm-energy proportional to their demand, plus a reserve margin. Each participant must individually contract its requirement as they please.
- Reliability Option: the contracts derived from this mechanism are a mix between a call option and a physical commitment to make capacity/firm-energy available in scarcity moments. The seller of the option commits to deliver capacity/firm-energy in scarcity times and forego the strike price revenue in exchange for a stable revenue stream. The buyer pays for an up-front fee but benefits from the security of supply and a reduced exposure to scarcity pricing. The buyer always receives the difference between the spot and the strike price every time the spot prices exceed the strike price.
- Payment for reliability: the regulator or the system operator estimates the price to pay in order to bring forward the required capacity. This price is paid either to all capacity providers in the case of market-wide mechanisms or specific technologies in the case of targeted mechanism.

A market structure that does not pay for the capacity availability, relying on price signals sent by the short-term market to ensure that investors build adequate capacity, is called an energy-only market. The “price caps” is usually called scarcity prices, and it is set high enough to incentivize firms to develop the required resources. Under this scheme, both energy and reserves rise above the generators’ bids when the reserves are drop below certain target levels [10].

3
Market design and system's physical characteristics

In this section, all markets will be compared according to their physical structure to correlate those characteristics with their existing market features. The markets were chosen based on similar characteristics to the Brazilian system or the adopted market model. Hence, they can be related to the Brazilian in size or electricity matrix and can have either suitable or similar market mechanisms.

The general Brazilian physical characteristics can be summarized as follows. In 2019, it had a network system that roughly covered 141.388 km of transmission lines, interconnecting approximately 170 GW of power generation, with a fuel mix of 64% hydro, 25% thermal, and 11% renewable. Also, the peak demand registered was about 90 GW [31, 32, 33]. In general terms, the Brazilian market is renewable-dominated, with the predominance of hydroelectric units, and it is large in terms of peak demand, and consequently, installed capacity. Also, it possesses an extensive interconnected and meshed transmission network. These characteristics highly influenced the market adopted, a single-settlement integrated cost-based model with a zonal, hourly, and *ex-ante* real-time price. Furthermore, there is no resource adequacy market based on capacity. The regulatory requirement of 100% coverage of demand by reliability credits based on firm energy is a joint product between electricity and reliability [34].

Table 3.1 differentiates the multiple structures into groups of levels of centralization (the darker colors indicate the more centralized markets). The cost-based power pools, also known as tight pools, are more centralized, not allowing participants to reflect their opportunity costs or inform physical contracts. Then, we have the price-based arrangements without physical contracts interfering in the dispatch. After that, there are the power pools with physical contracts considered for the dispatch. Finally, the less centralized are the unbundled markets with one or multiple power exchanges operating the day-ahead and intraday markets.

One reason to adopt the integrated cost-based model is to avoid abuse and market power in the short-term market. Markets with reduced competition either by the high market share of a few generating units or significant

Selected Markets	Integrated Markets		Unbundled Markets		Settlement		Physical Contracts	Agents' participation	
	Cost-based	Bid-based	One Power Exchange	Multiple Power exchanges	Single-settlement	Multi-settlement		One-sided	Two-sided
Brazil	✓				✓				
Chile	✓				✓				
Mexico	✓					✓			✓
Colombia		✓			✓			✓	
Ontario		✓			✓				✓
New Zealand		✓			✓				✓
PJM		✓				✓	✓		✓
CAISO		✓				✓	✓		✓
MIBEL			✓			✓	✓		
Nordics				✓		✓	✓		✓
Germany				✓		✓	✓		✓
UK				✓		✓	✓		✓

Table 3.1: Market pool classification

transmission bottlenecks can become vulnerable to market power. We can see from Table 3.1 that Brazil, Chile, and Mexico are integrated and cost-based.

Selected	Installed Capacity (GW)				Transmission Line (Km)				Peak	Capacity Share (%)			Selected
Markets	70<	70-90	100-125	150-220	30.000<	30.000-42.000	50.000-70.000	100.000>	Demand	Hydro	Thermal	Renewable	Markets
Brazil				✓				✓	90	64	25	11	Brazil
Chile	✓					✓			10.9	25	52	23	Chile
Mexico		✓						✓	50	16	71	13	Mexico
Colombia	✓				✓				12	68	31	1	Colombia
Ontario	✓					✓			27	25	61	14	Ontario
New Zealand	✓				✓				7	58	24	18	New Zealand
PJM				✓				✓	152	5	93	2	PJM
CAISO		✓				✓			47	18	54	28	CAISO
Nordics			✓				✓		67	47	25	28	Nordics
MIBEL			✓				✓		42	27	44	29	MIBEL
Germany				✓		✓			82	2	42	56	Germany
UK		✓			✓				48	6	68	26	UK

Table 3.2: Physical Comparison (2019)

According to [21], despite the substantial growth in generation capacity in Chile, there is still high concentration ownership. Additionally, the lack of experience in monitoring electricity markets and the observed electricity crisis in California motivated the regulator to resist the possibility of changing to a bid-based market. On the other hand, Mexico adopts a hybrid cost-based model allowing the participants to bid in a limited range around their audited costs. Their market was liberalized in 2014, and they created sophisticated market mechanisms such as multi-settlement and nodal prices, but their recent liberalization (which means that they are still fostering competition) justifies the slow pace towards a fully competitive market.

Another common reason for a cost-based market is to avoid externalities in bids and take advantage of the portfolio effect, which we believe was the main driver for the Brazilian market model preference. The large share of hydro generation with different owners in the same river cascade can contribute to such a decision since it creates the possibility of upstream plants interfering with downstream plants' inflow. This characteristic may lead to unfair behaviors such as bidding non-optimally to harm downstream plants. Thereby, upstream plants would force downstream plants not to produce to increase spot prices and induce market power. Moreover, that is a belief that only with global centralized optimization is it possible to allocate water strategically, benefiting from complementary seasonality between states, for example, dry season in one region and wet season in another [35].

Table 3.2 highlights in light gray, all hydro-dominated markets. New Zealand and the Nordics are very similar to the current Brazilian matrix, with a high share of hydro generators and renewable variable energy and a related proportion of thermal generators. Colombia has similarities with the Brazilian matrix at the beginning of reforms, with a high share of hydro and thermal plants. Despite their physical similarity, we can see in Table 3.1 that they chose significantly different market mechanisms. New Zealand and Colombia adopt an integrated single-settlement bid-based market while the Nordics chose the more liberalized model, the unbundled market.

New Zealand and the Nordics have the hydro-predominance, but in both markets, the river cascades have the same owner, diminishing the bids' externalities problem. Therefore, they do not adopt a specific mechanism to deal with this possibility [36, 37]. Like Brazil, Colombia has different owners in the same river cascade, but it does not use an explicit method to avoid bids' externalities through the same river cascade. Alternatively, it relies on the agents' will to set agreements to avoid such externalities and enhance efficiency through a joint operation. To diminish market power, Colombia includes a future market with CCP, adopts a price cap, and the reliability option's resource adequacy mechanism based on firm energy to ensure the security of supply [38, 39]. Since they have electricity and firm energy as separated products, consumers must procure, besides electricity, financial call options backed by physical resources certified to produce that energy during a dry period.

Because Colombia possesses plenty of flexibility provided by the hydro generators, their system is energy-constrained, explaining a firm's energy reliability credit choice. The hydropower stations can ramp up and down quickly, and the reservoirs' storage capacity makes it possible to transfer hydro energy from off-peak to peak hours, supplying demand in the short term. Conversely, in the mid-term, the system can be short in energy because of the system's dependence on the hydropower stations to ensure baseload supply. Under adverse hydrological conditions, the reservoirs will deplete, the water will become more scarce, and there would be a need to activate units capable of generating in dry seasons to attend demand. For the same reason, the Brazilian reliability credit is the firm energy. Nevertheless, both reliability and electricity are bundled in one product.

On the other hand, markets with a remarkable share of thermal plants, such as Chile, Mexico, PJM, CAISO, UK, and Ontario, adopt reliability credits based on capacity. Since there is a technological limitation on thermal units to provide energy in periods with a sudden change in energy consumption, the system operator needs to ensure enough generation to provide capacity at scarcity moments.

In addition to the resource adequacy mechanisms, the markets should also rely on realistic prices to induce the generation portfolio that better suits the system's needs. The benefits of granular prices in both spatial and time dimensions are well understood since they better reflect the operational reality. Higher time-frequencies would permit that the prices efficiently reflect the opportunity costs of flexibility, while higher spatial granularity indicates a need for transmission alleviation. In [40], he states that long-term efficiency naturally emerges from "getting the prices right" in the real-time market. By "right prices", he means that it should be tight with the operational reality (nodal, with adequate frequency).

The Brazilian spot prices until December of 2020 were zonal, weekly, and revealed one-week *ex-ante*. The hydro-dominated system implied a low price variability in the short term due to the hydro reservoirs' storage and generating capability of ramp-up/down quickly, making it possible to flatten demand in the short term. Hence, these physical characteristics justified the price choice at the time of the market implementation. However, due to its decremented hydro-dominance and the sector effort to modernize the market, since January 1st, the hourly prices were implemented, resulting from a day-ahead optimization model. The price mechanism and time frequency partly align with the international practices. Chile, Mexico, Colombia, the Nordics, and MIBEL also adopt hourly prices. However, New Zealand, whose electricity matrix is also hydro-dominant, has half-hourly prices. Additionally, in markets where thermal or intermittent resources prevail, like UK, Germany, Ontario, PJM, and CAISO, prices have higher temporal granularity. Furthermore, regarding spatial granularity, Chile, Mexico, New Zealand, PJM, and CAISO adopt nodal prices while the other markets adopt a zonal simplification (see Table A.2 for more detail).

The Brazilian settlement prices are similar to the Nordics' and MIBEL's because they are ex-ante, hourly, and zonal. The zones were decided based on a geographical division, like most European zones. Nevertheless, according to Table 3.2, the Brazilian size is considerably larger than most European markets, making the four-zone simplification even more problematic. For example, one Brazilian zone such as Southeast/Midwest [1], had a peak demand of approximately 53 GW in 2019, 26% higher than MIBEL's [32]. Yet, MIBEL

[1] The Southeast and Midwest geographical regions are aggregated into one electrical zone.

is divided into two zones, Spain and Portugal [41]. The Nordic region, closer in size to Brazil than MIBEL and with a similar electricity matrix, is currently divided into twelve zones [42].

Usual arguments for adopting zonal prices are that in great-sized systems such as Brazil, the nodal prices would become too complex to operate, and so many prices could inhibit market participants' attempts to settle long-term contracts. Nonetheless, Mexico, PJM, and CAISO prove that great-sized dimension systems can efficiently run a market with high-frequency and nodal prices. Also, the Western Hub in PJM is likely to be the most liquid forward electricity market in the world, proving that, although liquidity does not indeed happen in every node, the participants still have an incentive to trade in the forward markets [43]. According to [43], in practice, when transitioned to the nodal pricing, PJM saw its annual benefits to consumers reach approximately 2250 M$, with an implementation cost of around 150 M$.

Some also argue that markets with renewable predominance would gain little with locational price signals since those technologies are weather-dependent and consequently have specific places to be built. However, the locational prices are indicators for the transmission lines' enhancement and incentivize alternative resources such as battery storage or demand response. New Zealand is a market with a profile similar to Brazil, with weather-dependent resources, and use nodal prices. Hence, neither the size nor the energy matrix can be used as an impediment to adopting more frequent and granular prices.

One first forward trading environment that some markets use to address the real-time price variability is the day-ahead market. Especially in systems with a significant share of thermal units, it is efficient to plan the schedule for the next day due to the thermal generators' technical limitations such as start-up, shut-down, and run-time requirements. These characteristics are sometimes hard to be considered in the real-time market optimization when the operator must essentially rely on units already started (or a subset of faster generators, which usually have higher-running-cost). Settling the day-ahead schedules at the day-ahead prices gives the generators adequate incentives to comply with the agreements. The failure to comply could result in energy purchases in markets with higher and more volatile prices [44].

With the increasing amount of intermittent renewable production, many changes in generation output may occur after the day-ahead market closure. Any forecast error may incur substantially higher costs in the real operation in systems with scarce flexible resources. Studies such as presented in [45] show that the forecast error for wind significantly decreases with a shorter lead-time. Therefore, a market should adapt to the wind forecast changes during the day for a shorter period. The intraday markets effectively accommodate renewable uncertainty and reduce the re-dispatch balancing costs [44, 46, 47]. In Europe, where the renewable share is substantial, continuous intraday markets are widely adopted, and some markets also include a combination of both continuous and auction intraday markets. Likewise, CAISO also includes an intraday market in an auction form, referred to as a fifteen-minute market. In contrast, Mexico and PJM possess only day-ahead and real-time markets, which could be partially justified by the lower share of renewable generation in the electricity matrix.

This section highlighted the overall features of the different international electricity markets, mainly influenced by their physical characteristics. Along with the nomenclature defined in Section 2, they form the basis for the following section's critical analysis.

4
Market Comparison and Discussion

In general, electricity systems seek to create a generation portfolio that will accompany the load growth, handle any sudden imbalance, and bring economic efficiency. Even so, none of them have followed the same steps: while some remained with the highly regulated and vertical structures, others chose to deregulate and rely on the market competition to achieve such goals. The backbone of our study is the current market structures of some selected systems. We strategically selected twelve systems with different centralization levels and some common characteristics, such as size, energy matrix, or pricing methods, to make comparisons and outline our analysis. Usually, the first step for an electricity market is to deregulate and promote competitiveness. The second step is to improve economic efficiency, and, finally, the third step is to keep improving the mechanisms to accomplish political agendas such as decarbonization and technological improvements while ensuring safety and efficiency. In our selection, we encounter systems in the different stages of deregulation. While North America and Europe discuss the third step's topics, Latin-American deals with the first or second stages. Although some markets are at the same level, they do not necessarily adopt the exact mechanisms. For that reason, the international evaluation of current market designs and the observation of their next steps towards modernization are a great guide to find alternatives for the systems in the early stages, such as the Brazilian market, and trace acceptable practices by comparing systems in the same stages.

For a market to be efficient, it must be competitive and promote the right incentives for its participants by guaranteeing a realistic and transparent price formation. As electricity systems generally have many trading environments, they were analyzed based on their incentives to the market players. Our analysis begins with the operation itself because its expectations drive the players to make forward decisions.

4.1
Cost x Bid-based

The dispatch regime directly impacts the incentives for the different market players. For example, the cost-based integrated model's marginal prices may create misleading incentives since the system operator must have perfect and complete information about everything that concerns the system's operation and planning to allocate the system resources efficiently. However, ensuring that all data is providing trustworthy information is difficult for the system operator, and decisions based on inaccurate information may entail sub-optimal results. Accordingly, the most competitive markets choose a bid-based environment. In more competitive bid-based markets, the agents' profitability depends on an optimized bidding process, which aligns incentives to obtain reliable information for a proper risk management analysis. They decide on their risk aversion and, therefore, are held responsible for any consequences of their decisions. This process will only reflect the cost minimization of the system (i.e., social welfare) in a trading environment with perfect competition [48]. However, it is essential to highlight that neither perfect information gathered by one central agent nor perfect competition is reachable.

Therefore, more competitive environments seem to be more tangible once that a well-functioning market is implemented. To avoid market power and reach efficiency, a market must guarantee free entry and exit conditions, promote independence to the agents, implement effective market monitoring, and take the right measures to mitigate such abuses. Also, results found by [49, 50, 51] show that even with perfect information, by forcing the prices to be equal to short-run marginal costs, the cos-based models might incentive the investment in inefficient generation portfolios, reducing social welfare in the long run. Based on the arguments presented above, if enough effort is made to create a competitive market, the price signals from a bid-based market are more realistic, provide the right incentives to market participants, and promote economic efficiency in resource allocation. On the other hand, each market's physical characteristics, such as the small number of market participants, little transmission capacity, and large hydro producers, may create contexts where more liberal regimes lead to market manipulation and economic inefficiencies [52].

In the Brazilian case, the system operator must hold accurate inputs about the system's initial states (e.g., all reservoir levels) and model the uncertainties on water inflows and wind generation on behalf of all agents. In a continental country and hydro-dominated, holding accurate information about all reservoirs is impossible. Also, there are many criticisms concerning the long and mid-term planning models used to evaluate the opportunity cost of water. The probabilistic models and the data used to simulate the future water inflow scenarios are subject to disagreement among the participants. Besides, due to the high complexity of the mid and long-term planning models, they consider a simplified version of the system physics, which incur in "optimistic" water values [53]. The hydro generators address most unplanned deviations because they are flexible and capable of store water. Therefore, the optimistic cost of water allied with inaccurate inflow scenarios may lead to an unexpected depletion of reservoirs, demanding the operator make *ad-hoc* interventions in the system operation to avoid systemic risks. In this environment, where the agents do not interfere with the production of their enterprise, and cannot express their opportunity costs, regardless of their electricity sales commitments, if any decision results in losses, the injured agents may not feel responsible for it, which opens the prerogative for administrative and judicial disputes [35].

The bid-based model would decentralize the information, transferring the responsibility to the agents. However, to provide an efficient outcome, the markets should enable competitiveness and mitigate different market power sources. Bid-based markets such as PJM and CAISO adopt an automated local market power mitigation that cap the generators' offer when they can exercise market power. Because of the limitation imposed, they also adopt a resource adequacy mechanism where the reliability suppliers must submit self-schedules or bids into the day-ahead market (also known as must offer obligation), applying penalties for non-performance. Having a multi-settlement mechanism and more than one long-term liquid platform with the CCP for energy trading in physical and financial forms are additional features that increase competitiveness and incentivize proper behavior in real-time [54].

On the other hand, the European markets and New Zealand interfere less on specific strategies that need to be curtailed before the actual operation. They rely on anti-trust legislation and enforce rules stipulating appropriate practices to assess whether market power has been exercised in the previous operation. The Nordics, Germany, and New Zealand do not count on a resource adequacy mechanism, betting on high scarcity prices and strategic reserves procurement to ensure the security of supply.

The prices from either cost or bid-based dispatch can vary according to the level of details included in the clearing process. The more physical constraints are included, the more it tends to reflect the real system's opportunity costs. They can vary according to the spatial and time granularity and the level of information included, e.g. if the prices are *ex-post* or *ex-ante*.

4.2 Nodal x zonal spot prices

In relating to the settlement price's spatial granularity, the nodal pricing theoretical benefits are well understood. For example, in [55], he presents a version of nodal pricing that incorporates the technological externalities associated with the marginal cost of generation, the marginal cost of losses, and the opportunity cost created by congestion in the system. He demonstrates that a competitive equilibrium with property rights and their trading rule can lead to higher social welfare than zonal prices. [56] showed the superiority of nodal pricing for integrating wind into the German network. Both [46] and [57] relate that the increased deployment of VER would result in more transmission constraints and indicates the nodal pricing model as the better operation and investment signals. The VER's variability, allied with the fact that they are usually located far from the load centers, can create unplanned congestion in the grid. Therefore, it is more transparent to include the congestion costs in the prices rather than charge through tariffs.

The overall benefit of using a nodal-pricing model is that they better translate the system opportunity costs. The difference in price nodes indicates where there is a need for transmission alleviation on the system. Naturally, considering a competitive market, the participants would either take place at adequate locations or invest in transmission lines to relieve the transmission bottlenecks. Consequently, these prices are drivers for the market participants to make changes to maximize their profits, aligned with the systems' benefits. Although those prices provide the right incentives to generation and demand, they bring the need to hedge the price variation. A standard long-term contract may not be enough to provide the full hedge in transmission congestion cases, being necessary to have another market for transmission congestion contracts, for example, the FTRs. The FTRs, provide a full hedge in transmission congestion, gives the incentive to build transmission lines in the right places, and redistributes the congestion revenue that the system operator collects. Chile is the only one that does not has a market for FTR between the markets that adopt nodal prices.

The Figure 4.1 shows the selected markets divided by their price realism according to the spatial granularity and resource scheduling criteria. The more upward the country is, the more granular is the price. In the x-axis, we measure the degree of decentralization of the market concerning the dispatch. It goes from a highly centralized dispatch (cost-based) to a decentralized with physical contracts influencing the dispatch. Even though the nodal-pricing benefits are concrete, markets such as Brazil, Colombia, Ontario, and the Europeans, adopt either single-pricing or zonal-pricing models due to their higher simplicity. Ideally, if the zones were chosen so that all aggregated nodes have the same prices, they would give the same economic signals from the nodal pricing. However, clustering the zones is not a trivial task [1], and generally, they are not selected based on a systematic methodology, but instead on expert judgment or geographical division [60]. The Brazilian zones were decided based on a geographical division, like most European zones. Nonetheless, the zone splitting in Brazil is the same since the creation of the market and there is no intention to change, while the European set rules (Commission Regulation (EU) 2015/1222 July 2015) on reviewing the existing bidding zones whenever internal constraints persist [61].

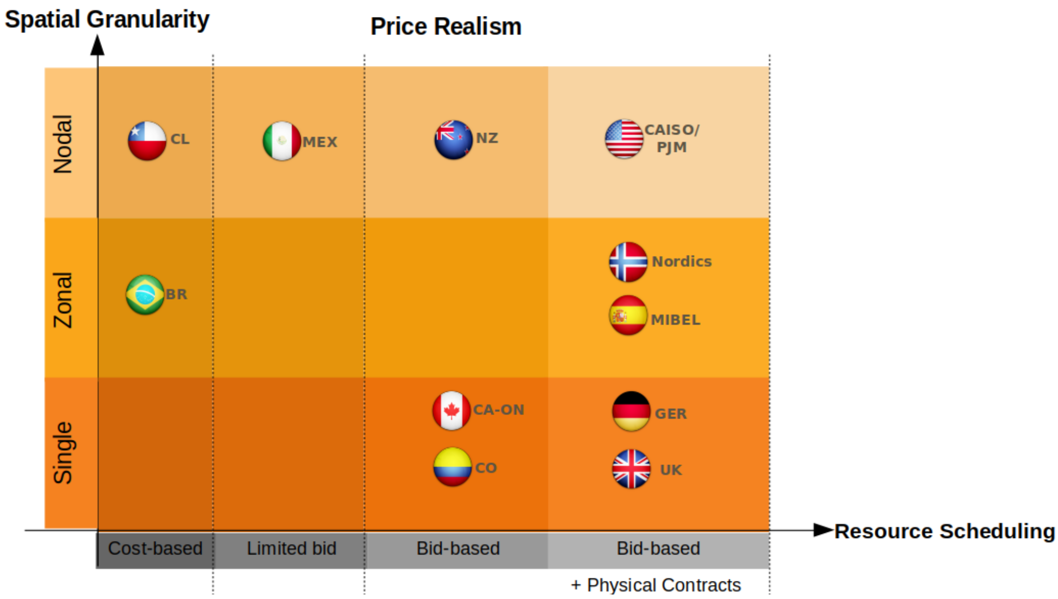

Figure 4.1: Price realism according to the spatial granularity

Whenever that is intra-zonal congestion, some out-of-merit resources offset the in-merit generation to satisfy the constraints ignored in the pricing model, creating re-dispatch costs, socialized with the consumers. Therefore, when the intra-zonal congestion is frequent, the generation units could take advantage of participating in re-dispatch (the so-called “inc-dec” game). The fact that the suppliers are compensated for being “constrained-off” or “constrained-on” impacts the prices they offer to the wholesale energy market [19]. For example, suppose a unit is paid the bid price for electricity when located in a region with scarce supply, and it knows it will be restricted. In that case, a profit-maximizing unit owner will present a bid price much higher than the variable cost of unit operation, thus raising the total cost of electricity to

[1]Different approaches are discussed in [58, 59].

end consumers. The opposite case can also occur; generators who know to be constrained-off face underbidding incentives because they receive the difference between the spot and their bid.

According to [60], in a zonal bid-based environment, even with modest transmission costs over a year, such as 1 $/MWh, the market participants could change their behavior. These behavioral changes can substantially affect system operations and are harder to perceive since the costs are averaged over all system users. Market abuses in these circumstances were observed in California in the 2000s through the inc-dec games. As stated by [62], the CAISO intra-zonal congestion costs were irrelevant at the market's implementation. When the market evolved and competition increased, the congestion followed a different pattern, and the new zones creation lagged behind considerably. From 2002 to 2003, the congestion costs increased ten times, and the agents benefit from it. Although this was not the only cause of the California crisis, it is considered one important factor. After the crisis, CAISO recognized the flaws from the zonal pricing and changed to the nodal approach.

Studies conducted in [63] show that inc-dec games are also likely to happen in European countries, such as the Nordics and the United Kingdom. Improvements in the representation of the transmission lines may reduce the system vulnerability to these problems but not completely eliminate them. However, the nodal price implementation does not seem to be in the European electricity markets' scope yet. Although they recognize the advantages of nodal pricing, the cost benefits analysis has not been carried out, and there is a belief that the transition costs would likely surpass the implementation benefits in the short term. Adopting the nodal prices would demand fundamental structural changes in the whole continent. The transition is considered more difficult due to how the European markets were conceived: unbundled and deeply connected with several countries through the day-ahead and intraday power exchanges, with separate balancing markets run by the system operators. Changing to nodal prices would require a closer harmonization of the balancing markets, demanding changes in the cross-zonal trading, incurring significant technological and institutional re-configuration [61].

The recent modernization in Brazil implemented the dispatch model with transmission constraints (1st and 2nd Kirchhoff's Law), half-hourly dispatch instructions, and unit-commitment constraints disregarded before. The price mechanism considered is the dual variable of the balance constraints between demand and generation from this model, considering a simplified version of the transmission constraints (at the four-zone spatial granularity), hourly frequency, and established one day-ahead. The price simplification brings some economic inefficiencies that go against common sense. One of them is that intra-zonal congestion is infrequent and insignificant to drive a change towards nodal pricing, the Figures 4.2 and 4.3 show the cumulative distribution function of the difference between the nodal and zonal marginal costs in the Brazilian electricity market. The Figure 4.2 exhibits the price difference for a chosen month (march/2020) while Figure 4.3 shows the price difference for the whole year of 2020, divided between the dry season (May to November) and the wet season (December to April), excluding January due to the lack of data. The data was collected from the outputs of the short-term model made available by the Brazilian system operator[2].

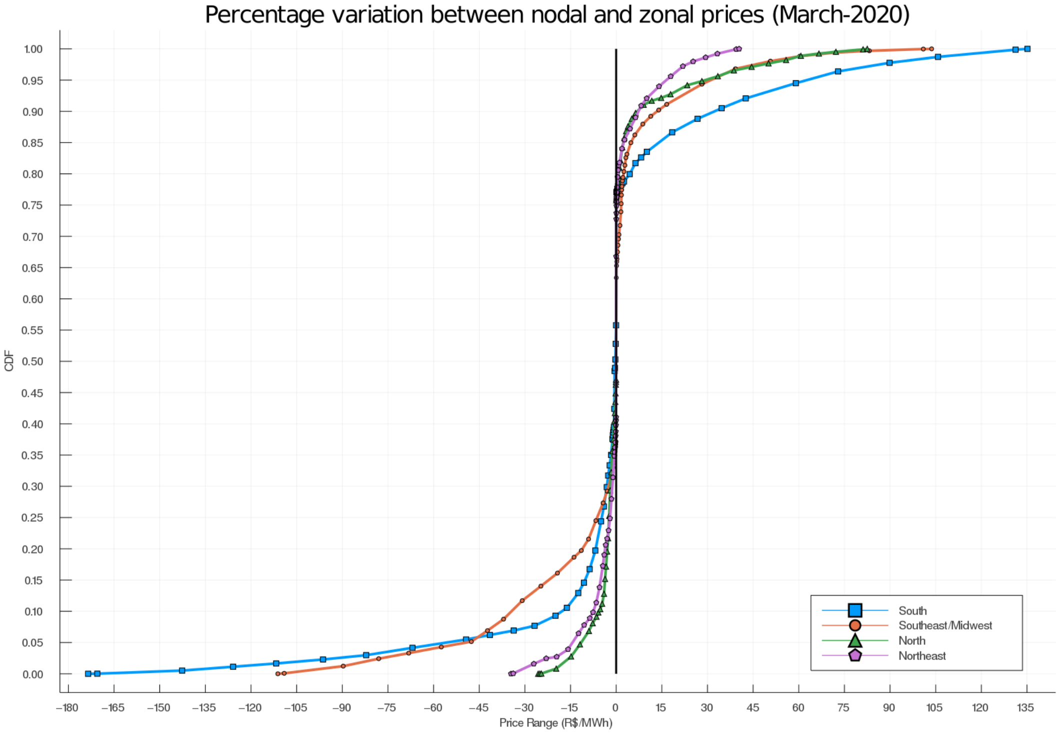

Figure 4.2: Percentage variation between nodal and and zonal prices (March/2020).

From the graphs, we note the wide range in price difference, meaning that the nodal marginal costs assume extreme values in both directions (both lower and higher than the zonal marginal costs). For example, in March, the South zone had the nodal marginal costs varying around the zonal marginal cost, about 150 R$/MWh. However, it is worth highlighting that 87% of the data are in between -50 R$/MWh and 50 R$/MWh. In the same month, the Southeast/Midwest zone demonstrates that 18% of the nodal prices are at least

[2]The 10% less frequent prices were excluded from the analysis

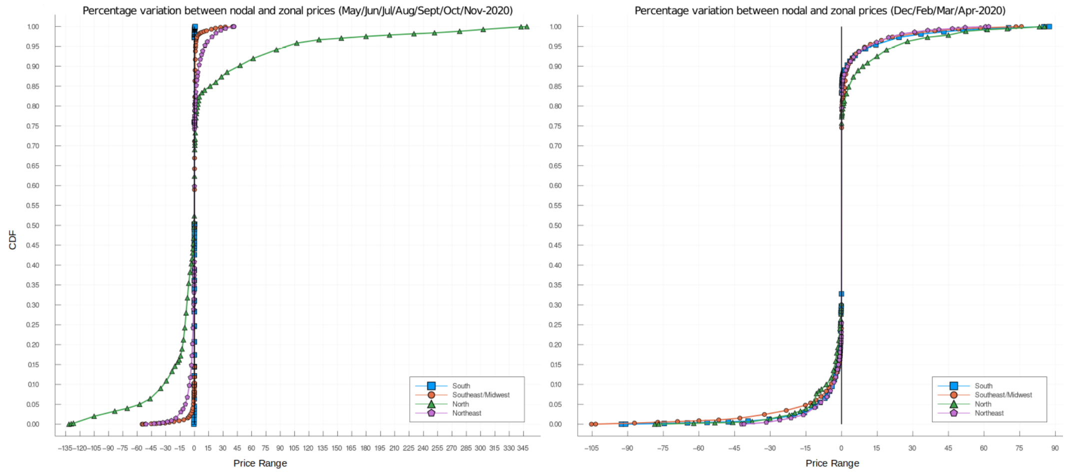

Figure 4.3: Seasonal percentage variation between zonal and and nodal prices (2020).

15R$/MWh lower than the zonal prices, achieving the maximum difference of 110 R$/MWh.

Analyzing the 2020 year as a whole from Figure 4.3, we note that the North zone stands out for the highest range in the price difference in the dry season, going from -135 R$/MWh to 330 R$/MWh. Also, approximately 10% of the nodal prices are at least 25 R$/MWh greater than the zonal prices, while and 12% of the zonal prices are at least 15 R$/MWh lower. Because the Brazilian market is cost-based, it should be no worries about the “inc-dec” games. However, these results confirm that price simplification is a significant source of hidden costs prorated among consumers. Furthermore, if considering migrating to a bid-based environment, the zonal division should be reconsidered.

4.3 Spot prices time-granularity and information level

In addition to the spatial granularity, shorten the time-granularity of the settlement prices, adjust the gate closure of the markets to release prices, and dispatch instructions as close as possible to real-operation is advisable for achieving more transparency in prices. Both enhancements would permit that the prices efficiently reflect the cost of variability and allow the units, especially the VRE, to correct their forecast errors and update their dispatch plans [46, 64]. According to [65], their first view of what a market with a high VRE share should have is: real-time prices in the most granular way possible to reflect reliability needs and incremental changes in the supply and demand. Also, [40] recommend that all markets begin with releasing real-time prices close to physical reality, and as necessity appears, the forward market layers must be built.

The Brazilian market followed the opposite trend by creating first weekly and long-term markets; and, recently, changing to the day-ahead and long-term markets. Although the day-ahead hourly prices from the Brazilian market are a tremendous recent achievement (compared with the last mechanism), there is a concern about its sufficiency given the prospects for insertion of variable renewable energy. The [66] indicates that the hydro units will reduce capacity share from 64 % in 2019 to 53 % in 2027, while the variable renewable energy will increase from 11 % in 2019 to 28 % in 2027. The Brazilian market would become even closer to the Nordics system within the projected generation fleet. Recognizing the price frequency's importance in this context, the Nordics already plan to change their balancing prices and settlement periods from one hour to 15-min until 2023 [67]. Furthermore, they already possess day-ahead and intraday markets for energy trading.

All other single-settlement markets referred at Table 3.1 seem to be following the recommended enhancements, discussing the improvement of real-time prices and sequentially the possibility of adding day-ahead markets. New Zealand has nodal and half-hourly real-time prices, enclosing inter-temporal constraints. At the time of its liberalization (1996), it also included a day-ahead market, but the market was subsequently abandoned due to the lack of liquidity, justified by the hydro predominance and its consequent low price volatility [68]. Recently, with reduced participation of hydro generation by intermittent resources, the benefits of implementing at least a day-ahead market should be revisited. Indeed, [68] had already foreseen its benefits for New Zealand since 2003. The New Zealand real-time market allows the generators to bid one day-ahead and adjust positions until two hours before the operation. This approach creates the opportunity to withhold generation or raise bids at the last moment when the operator has less flexibility, which would incur higher prices. One way to avoid such behaviors could be closing the gate the day before as Colombia does, but this could inhibit the agents from reporting real changes in the expected supply [69].

Ontario already adopts high-frequency prices (5-min frequent), but they do not include transmission constraints and are single-settlement. Also, following the suggested recommendation, in [70] they propose enhancing real-time price signals by including transmission constraints and implementing multi-settlement mechanisms. Likewise, in [21] they state the importance of including inter-temporal constraints in the price mechanism, current disregarded in Chile, increasing the price frequency, and implementing at least a day-ahead market.

Another possible source of hidden costs comes from "real-time" prices calculated before operation. The *ex-ante* prices may become too detached from reality depending on the distance in time from the system operation, which increases the necessity for side payments such as re-schedule costs. In Brazil, they are released one day-ahead, and as many changes occur after the day-ahead market, different generators can be called to address the unplanned deviations. Because the *ex-ante* prices are settled with the metered generation, the prices previously released may not be enough to recover some generator's marginal costs. Hence, there would be no compatibility between prices and quantities, and the re-schedule costs would be necessary to cover the unexpected costs.

Except for Brazil, all single-settlement integrated markets (Chile, Colombia, Ontario, and New Zealand) adopt *ex-post* prices, based on metered demand. This approach's primary goal is to release prices as consistent as possible to the actual resource outputs, but they also present inconsistencies. For example, Colombia and Ontario use the real demand in a pricing algorithm more simplified than the dispatch instruction, disregarding the transmission constraints. Therefore, the pricing algorithm creates an entirely hypothetical dispatch from the optimal solution of demand and a simplified version of the physical reality .

In Chile, the *ex-post* prices are given by the variable cost of the last dispatched generating unit that is in a position to satisfy an increase in demand in each time and location. In this case, prices and quantity are compatible because they come from the units' responses to real demand. However, since the prices are not calculated based on the dual variable of the balance constraints between demand and generation, price signals fail to enclose inter-temporal constraints, likely to under compensating flexible units [21].

On the other hand, the New Zealand method to calculate *ex-post* prices is to solve the exact *ex-ante* dispatch problem using the real demand and derive the *ex-post* prices from the marginal units. Although this mechanism seems to be better suited than the previously mentioned, it is also susceptible to inconsistencies. Since the unit's production may change after the dispatch instruction and their responses are guided by reserve and regulation services, their outputs to deviations are not necessarily optimal. This approach cannot reconstruct the whole generation response and instead creates a re-dispatch based on real demand, achieving a "perfect" least-cost solution different from the real one. Also, both New Zealand and Chile co-optimize energy and reserves for the dispatch instruction, planning an efficient use of both services, but they pay the same price for energy and reserves, the *ex-post* energy prices.

Among the integrated markets, PJM, CAISO, and Mexico adopt *ex-ante* prices, but they are calculated from the last dispatch instruction (around 10 and 15 min *ex-ante*) most likely to reflect real operation. After the last dispatch instruction, all sudden changes are addressed by reserve and regulation resources previously procured and committed through the co-optimization with energy. There is an energy price, and each type of reserve provided resulted from the marginal unit needed to supply the expected demand for an individual product. Since these markets' prices could be very volatile, they also adopt multi-settlement mechanisms to hedge against variation. PJM and Mexico have both day-ahead and real-time markets, and CAISO also includes an intra-day market.

Figure 4.1 puts the selected markets together, comparing their price realism according to the frequency and information level of the prices and their centralization. The lighter frames indicate the most adherent economic signals. From both Figures 4.4 and Figure 4.1, we can observe that the European are very decentralized but adopt the least granular prices, with simplification on the pricing mechanism (either zonal or single prices). The Nordics and MIBEL use hourly zonal prices while Germany and the UK adopt less than hourly, but single prices, the North-American and New Zealand chose more granular and nodal prices. Between them, CAISO and PJM are the most liberalized permitting physical contracts on the dispatch. Furthermore, the Latin-Americans remain in the least realistic area, with Colombia standing out positively by being the only bid-based market and negatively by having the most simplified price (single pricing). Brazil stands out as an outlier by being the only market with weekly prices with disclosure one-week ex-ante. Besides, although Brazil adopts zonal prices, it is a continental country divided into four zones. Thus, each zone may correspond to a system like the United Kingdom in terms of size.

We can note from the international experiences that, both *ex-ante* and *ex-post* prices deviate from the physical reality. Nevertheless, the *ex-ante* prices, when calculated close enough to the real-time markets and co-optimized with ancillary services, tend to align with market incentives, clearly separating the prices for energy from any specific services allocated to ensure security of supply for a short horizon.

All features discussed until this topic revolve around a common goal of enhancing the economic signals from the short-term market prices. It seems to be common sense that the prices should reflect physical reality the best way possible in every market environment and that the multi-settlement

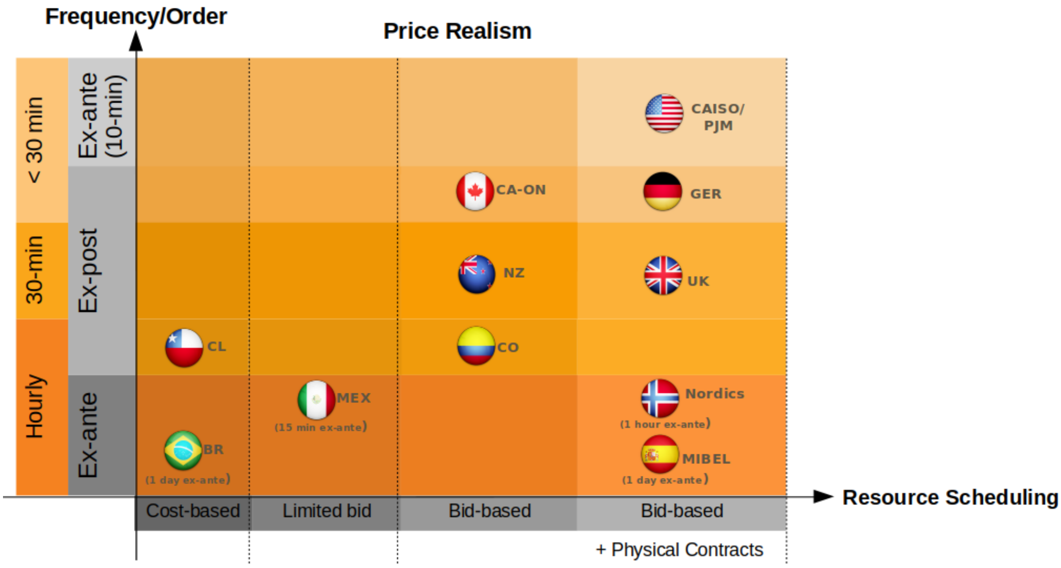

Figure 4.4: Price realism according to frequency and information level

mechanisms can mitigate market power and bring the price realism to the other market layers. If enough effort is made to create a competitive market, the price signals from a bid-based market are more realistic, provide the right incentives to market participants, and promote economic efficiency in resource allocation. However, many markets remain with simpler structures. There is always a trade-off between goodness of fit and parsimony. In this case, the realistic prices can bring operational complexities and implementation costs, while simplified models are easier to operate and do not require many changes. However, the more simplified is the model adopted, the more it will yield economic inefficiencies and need more regulating interference on the investment decisions.

4.4 Long-term markets

Reliable and transparent prices in the short-term markets induce more liquidity in long-term markets. In fact, both trading environments are directly connected when long-term forward or futures contracts have underlying short-term prices (e.g., from day-ahead or real-time markets). When the participants trust and understand the prices that underlie their contracts, they feel more comfortable taking different positions on forward markets to hedge against the volatility, increasing liquidity. Generally, in these competitive environments, an exchange is set up to provide the tools to facilitate the gathering of buyers and sellers of financial and physical contracts for future delivery. Consequently, we understand that one way to measure market liquidity is through the presence of exchanges and their characteristics.

Many believe in the scarcity pricing from short-term markets and liquid forward environments as the solution to electricity's natural incompleteness. According to [71], the resource adequacy mechanism is only the third-best solution, while the best includes eliminating the leading underlying causes and enhance the price signals of energy and reserve and regulation services.

The Nordics, Germany, and New Zealand allow very high prices in the short-term markets and foster competitiveness through liquid forward platforms with CCP, offering different types of financial products [54]. In other words, they do not rely on resource adequacy mechanisms (see Table A.1). Among the selected markets, Germany is the one that offers more platforms for derivatives trading. They have four exchanges: ICE, Nasdaq, EEX, and OMIP, with a broad of products offered (see Table A). Due to their high amount of VRE, the region aims to give the generators the possibility to adjust their positions, enabling their finance and profit-making.

Although the exchanges for energy trading are a great tool to achieve competitiveness and price transparency, systems that do not count on resource adequacy mechanisms are generally criticized as jeopardizing the market's reliability by relying on volatile prices possibly distorted by strategic behavior and market manipulation. In this context, CAISO, PJM, and Ontario limit the participants' bids and adopt a resource adequacy mechanism for the units to recover the missing money and attract new units capable of providing capacity. CAISO places the responsibility on the consumers for long-term procurement to ensure sufficient capacity to meet system and local reliability requirements. The price from the reliability obligation tends to be less transparent than in centralized mechanisms. Because PJM and Ontario lack flexibility ratified by the seasonal changes, they implemented yearly reliability auctions with seasonal obligations [10, 72].

The resource adequacy mechanisms are also used to encourage risk-averse investors, especially in systems with growing economic development rates and lower and more volatile market prices due to renewable generation participation. This is mainly the case of Chile, Brazil, Mexico, Colombia, and the UK that adopted resource adequacy mechanisms to foster new investment through long-term PPAs, providing a more stable investment signal that would shield investment decisions from the possible setbacks of the short-term markets [12, 73]. Table A.1 summarizes the approaches currently adopted by the selected markets. We can see the broad range regarding the methods' specifics which is driven by the necessity of each market.

The "adequate" mechanisms to overcome the market incompleteness and ensure efficient and reliable delivery are ongoing debates in the short and long term. There are different RAM forms, and even in the same procurement method, it can be distinct rules regarding the payments, delivery periods, reliability credit calculation, and incentives for performance. All of the existing methods have their share of success in inducing new investments, but there are still concerns about whether they can assure efficiency. That is, if the procured resources will deliver electricity when the system is most constrained and if they succeed in preventing market manipulation [10].

The reliability markets assume the introduction of a series of regulatory rules. The first is the definition of reliability credits which can be straightforward for thermal plants but can become arbitrary and non-realistic for renewable sources. Miss-calculated reliability credits may lead to cross-subsidies, where the technology with more credit than the ideal would have the incentive to over-investment while the one with less credit would be motivated to under-invest. In such cases, the reliability payments could ensure an adequate installed capacity and correct the missing money problem, but depending on the bias, the consumers would suffer from either high prices or a lack of firmness (energy generation at scarcity moments). The larger the income from the reliability markets, the more critical become the reliability credit biases.

An *ex-post* evaluation of reliability credits based on historical availability on scarcity events can result in errors depending on the criteria adopted to define such events. According to [74], the spot market price would be the best indicator of critical periods since the other standard criteria may not be the moments when the reserve margin is tightest. Although the *ex-post* method can be an incentive to improve the generators' efficiency because they are rewarded depending on their measured performance, they may not be the best proxy to reflect future reality. On the other hand, a look ahead analysis is based on the regulator's assumptions on future outcomes. This method may be better suited to define a reliability value for new entrants. However, the long-term assumptions such as demand, water inflow, and wind generation are hard to be assertive and are usually subject to a lot of controversy [74]. Ideally, the look-ahead model should use a chained operational model to forecast future operations in a window horizon no longer than a year to estimate each resource contribution being as adherent to reality as possible. In [53], they ratify the importance of a planning model attached to the operational reality, since simplifications in transmission lines modeling and in security criteria implies in a optimistic bias possibly resulting in unexpected reservoir depletion and spikes in the spot prices.

Therefore, while the resource adequacy mechanism allied with price caps could be a good tool to mitigate market power, such mechanisms' details must be carefully thought. [75] showed that the market abuses are still present in Colombia, despite the reliability option adopted. They pointed that the reliability option combined with forward contracts is vulnerable to market power since some generators could artificially induce scarcity moments when it provides a profit-maximizing income. The results were demonstrated through an illustrative model and empirical evidence from the Colombian reliability option market.

In Brazil, the regulated consumers must procure reliability (bundled with electricity) in public auctions whose obligation period goes from one year until thirty years depending on the auction, while the non-regulated have the freedom to choose their contract specifics. The mechanism's main goal was that demanding the consumers be 100% contracted in firm energy, both safety, and economic criteria would be assured along with the generator's finance. Some problems of this approach are: (1) it defines most of the generator's revenue, (2) ex-ante evaluation of reliability credits for an extended period ahead, (3) limited prices, and (4) separated procurement environments.

1. Because it defines most of the generator's revenue, the reliability credits cannot be drastically changed[3], since it would imply unpredictable financial risks. Indeed, there is pressure for not changing it at all (the first and only ordinary revision of the hydro units' happened in 2017). However, the system condition is not static, and the inclusion of new features (either a generator or a transmission line) affects the whole system and can either increase or decrease a unit's reliability credit. Therefore, the reliability credits should be periodically revised to adjust the unit's contribution to the current system conditions.

2. The same model that calculates the opportunity cost of water in long-term planning is used to evaluate the reliability credits. The operator attempts to estimate the unit's contribution in the critical forecast periods. This approach is questionable since many system important details are disregarded in their calculation, and the assumptions considered in the model are subject to controversy, hence resulting in a hypothetical assurance. The simplification in the reliability credits calculation and the lack of revisions make the commercial certificates unattached from the real system firm energy and artificially high. Hence, the consumers being

[3]There is a rule that the hydro generators' reliability credits must be revised every five years. It can also be extraordinarily reviewed, but the maximum change is limited to 5% of the original reliability credits.

100% covered do not guarantee the planning stage's safety and economic criteria.

3. The capped prices do not incentivize peaking units nor demand response. In a market with a high share of hydro generators with large reservoir capacity, the price limitation had little impact. When the consumers contracted energy, it automatically contracted flexibility, ensuring the system firmness. However, due to its environmental impacts, the procurement of hydro with large reservoirs was constrained while other renewable generators such as wind, solar, run-of-river hydro units, and biomass increased competitiveness, and consequently its capacity share. Nonetheless, these technologies have a lower contribution to the system firmness. Therefore, due to the spot prices' limited potential to attract peak units, there is an increasing concern in procuring a set of technology to ensure supply security through capacity.

4. The procurement of an adequate fleet of technologies to guarantee the system firmness is mainly assured through long-term public auctions. Potential investors negotiate with several distributors (the energy retailers) and regulated consumers. Keeping the obligation only to the regulated environment create the "free ride" problem. The consumers who are not compelled to participate in the auctions can avoid these costs and benefit for free. This asymmetry encourages large customers to abandon the regulated environment, leaving the regulated costs even more expensive. This characteristic limits the possibility of expanding the non-regulated environment. Furthermore, while demanding consumers to be backed by firm energy with extended obligation periods can facilitate the participation of new entrants, too long periods can lead to market inertia in accommodating new technologies and regulatory changes [35].

All market except Brazil evaluate their reliability credit yearly and share the reliability costs among all the consumers. Furthermore, the obligation period for new enterprises in Brazil is the largest. To overcome the pointed issues of the current resource adequacy, the Brazilian market could either adapt the mechanism to achieve the benefits suggested by [26] or unbundled reliability and electricity in different products.

In his work, [26], argues that generation adequacy can be ensured by setting a market for standardized fixed-price forward contract (SFPFC) and mandating consumers to purchase a share of their demand some years in advance with delivery periods longer than one year. He proposes that the market operator should run periodic auctions where consumers would purchase a defined proportion of their realized demand and generators sell energy. The idea is to assure liquidity in forward markets (resolving the “missing market” problem), while the contracts would be functional to partially avoid market power, guarantee a fixed income for the new entrants, and provide a financial hedge to consumers. The price caps could be loose at all times (instead of the specific set of hours defined as scarce, common in the RAM), sending adequate signals for flexible resources (such as batteries and demand response) and for generators to comply with their agreements, incentivizing performance. The more realistic the prices, the more the generators would be impelled to supply at scarcity moments to avoid being financially exposed. This methodology does not impede the negotiation of other agreements. Indeed, it is expected that the hedge markets play a crucial role in this environment. The necessity of trading other derivatives should increase since the renewable generators with fixed price and quantities contracts are exposed to the quantity risks, especially at high and volatile spot prices. Hence, the cross-hedging between generation resource owners, enjoying the portfolio effects, is likely to become more common.

Furthermore, he eliminates the necessity of some regulatory burden, such as defining the scarcity moments and the calculus of the reliability credits. Nevertheless, this structure is idealized to work in a market with the “right” price signals. Otherwise, many of the expected outcomes would not realize, such as the generator’s performance, the resources’ attractiveness that would alleviate the system’s needs, and correct the “missing money problem”. In this mechanism, the Brazilian market would have to provide the same energy procurement platform for every consumer, equalizing the contract details such as obligation and lag periods. Also, the spot prices should reflect adequate spatial and time granularities with higher caps. Therefore, all consumers would contribute to new agents’ entry, and the enhanced price signals would incentivize the generators to perform at scarcity conditions. The market should also provide a liquid trading platform to allow the trading of other products facilitating cross-hedging between different generation units.

The second possible solution would be untangling reliability and energy, as many other markets do. Along these lines, all consumers would bear the reliability costs, and the energy trading could be maintained the way it is (decentralized for a set of consumers). Mexico and Chile follow a similar approach mandating the consumers to have part of their demand backed in energy contracts. Chile demands the consumers to be 100% contracted in energy, where the regulated consumers must procure PPAs in electricity auctions. Chile also pays for reliability whose prices are decided in a regulatory manner, and every generator receives a payment proportional to their reliability credit verified *ex-post.*

In Mexico, the entities that serve regulated consumers must subscribe to electric coverage contracts exclusively through auctions, although other entities can participate if interested. They are promoted by the system operator and are a combination of three different products; energy, capacity, and clean energy certificates (CECs) [76]. The regulated consumers must have 100% on PPAs while the non-regulated ones must have 60 %. They must comply with the requirement for the next three years, and after that, the obligation reduces proportionally to the distance in time (until eighteen years ahead). The energy agreements are utilized to guarantee the finance of new generators entry, while the resource adequacy market aims to ensure revenue adequacy to the units and attract capacity into the market. At the end of each year, the system operator verifies the units' reliability credits and the consumers' obligation. The participants whose capacity contracts were insufficient to accomplish the requisites must buy the missing quantities at a balancing capacity market.

The *ex-post* verification can be useful for incentivizing performance, and the yearly update of the reliability credits is ideal for reflecting the contribution of each resource in the market's current structural form. However, measuring scarcity through the peak load may not be a good proxy for calculating reliability credits in a renewable-dominated market. Also, as [77] and [26] observed: if a mandatory energy purchase is already in place, the necessity of an additional resource adequacy mechanism is questionable. Indeed, a study conducted by [78] compared the current framework in Chile with an energy-only model with higher cap energy prices and the mandated forward contracts in energy. They show that under the proposed framework, the generation unit owners get almost the same revenue stream as in the current regime. However, the higher price volatility leads to a prudent use of the reservoir water and gives incentives to demand to reduce consumption and generators to be available when needed most, bringing more reliability to the system.

Whether the forward agreements are used as a principal and regulated mechanism for resource adequacy or not, they are crucial to foster competitiveness and diminish market power. Therefore a market with liquid derivative platforms is paramount to achieve market maturity. Although the electricity markets need regulation to some extent, the aspiration is to progressively reduce intervention, giving the agents autonomy and the means to achieve revenue stability and profit income in a volatile and imperfect market. Markets such as MIBEL and New Zealand started their liberalization with mandatory energy procurement to reduce market power and achieve energy platform liquidity. After they accomplished the competitiveness, offering different financial products, they suspended the mandatory contracting. Their current platforms ASX and OMIP have both CCP and a wide variety of products such as Future, Options, Spread, and Swaps to meet the agents' diverse needs (see Table A).

Figure 4.5 intends to classify the markets accordingly to their liquidity. The y-axis relates to the variety of products traded in exchange and has the following scale: none products, only Deliverable Forward/Futures, passing through Financial and(or) Deliverable Forwards/Futures, and finally, the most liquid are the exchanges that offer Financial/Deliverable with other products besides Forward/Future, such as Options, Spreads, and Swaps. The concept of liquidity on the x-axis is related to the amount of existing exchange with the CCP. Thus, the markets with more than one exchange with the CCP and many products, Financial and Deliverable, are more liquid and have more price transparency. The markets with less intervention and better price signals possess the more liquid derivative environments from this Figure. For example, all bid-based markets have derivatives platforms with CCP, and the ones with very granular prices, such as PJM, CAISO, and Germany, are also the ones with more platforms.

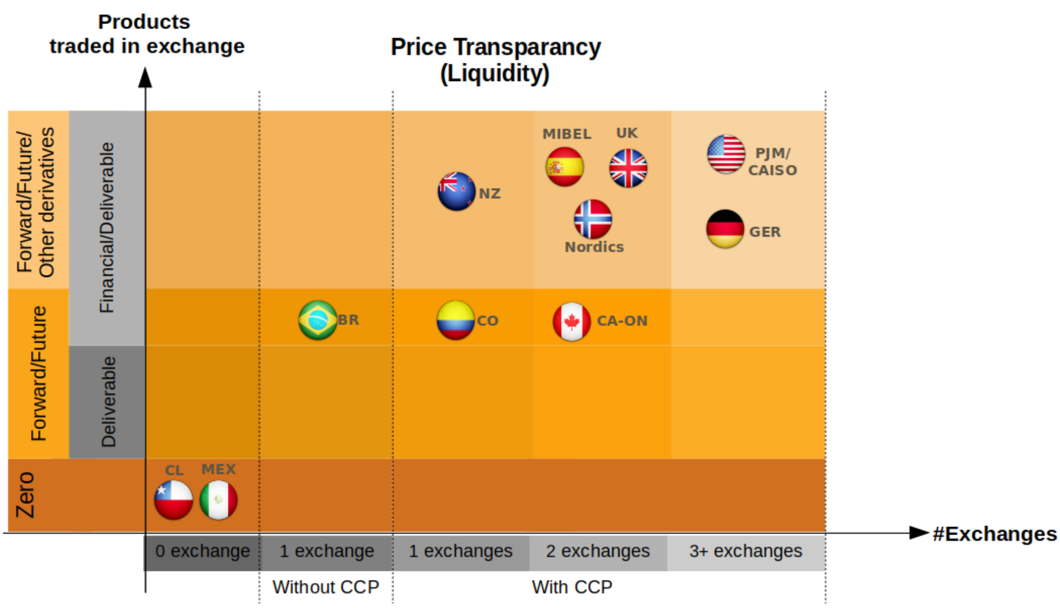

Figure 4.5: Price transparency according to number of products and exchanges

On the other hand, Chile and Mexico are highly centralized (cost-based integrated markets) and do not have a derivative platform, relying only on bilateral agreements. Despite the presence of platforms in Brazil, they still do not have CCP implemented. Nevertheless, since 2021 BBCE (a platform for energy trading in Brazil) began offering energy derivatives and made the forward curve visible to their customers. The new products indicate a progression towards liquidity and price transparency, paving the Brazilian market way for a more mature and competitive market.

5
Discussion on the adequability of the international experiences to the Brazilian market

In the Brazilian public consultation (CP) nº33/201 proposals, we can see the concern on achieving modernization through a coordinated reform, respecting the priorities, and the system's singularities. They focused on looking at the system as a whole, identifying the core of the problems, and offering generalist solutions. There are several proposals, but we will focus on the themes approached in this work. They suggest starting with enhancing the price signals since they are the drivers for an efficient generation expansion. By better prices, they mean as close to the actual operation as possible and from a bid-based market.

5.1
Pools

Regarding enhancing price signals, the Brazilian market has already advanced implementing hourly day-ahead prices and have a proposed bill PL 414/2021 under analysis [1] that would make possible, among other things, the implementation of the bid-based market. Nevertheless, to the best of the authors' knowledge, little has been discussed about implementing granular prices (in spatial dimension) and an *ex-ante* closer to the real operation. Figures 4.2 and 4.3 show that the Brazilian prices present considerable intra-zonal congestion. Therefore, its prices' reduced spatial granularity already brings economic inefficiency due to the high hidden costs. In a bid-based market, this inefficiency could also become a source of arbitrage profit among the agents. The nodal pricing does not guarantee market power extinction but makes them visible and transparent that can be resolved with risk mitigation tools like PJM and CAISO do.

The Brazilian market could consider implementing the multi-settlement markets with nodal prices in the cost-based approach to transition to the bid-based approach, like current in Mexico. In this case, the market operator would postpone implementing the market power mitigation tools, which would avoid

[1]The proposed bill is originated from the CP 33 suggestions and has been in progress since 2016. It was already approved by the Senate and is awaiting approval from the Chamber of Deputies.

regulatory burden and expenses from the market power mitigation. Also, the revenue from the nodal price differences could help finance new transmission lines, diminishing the transmission bottlenecks and the possibility of market power in the planned bid-based market.

If implementing a multi-settlement bid-based mechanism, the Brazilian market could follow two different paths: the integrated or the unbundled. The unbundled market with the power exchanges was supposed to be simpler and grant the agents most of the balancing responsibility. However, this model became more complex and less transparent as different bids were allowed, and it is not suited to implement nodal prices and a co-optimization of energy and reserves, which we consider as fundamental to an ideal price signal. Besides, the migration from an integrated cost-based to a bid-based market requires fewer structural changes than an unbundled one. In a integrated and multi-settlement market, the real-time prices would have to be either *ex-post* or a closer *ex-ante*. We advocate in favor of a closer *ex-ante*, such as the PJM's prices, because it is more aligned to the market incentives.

While waiting for the bill PL 414/2021 approval, several studies and discussions are promoted by the agents and the government. They try to address the technicalities of implementing the bid-based market, such as market power mitigation and managing the hydrology risks (the adaption - or not - of the Energy Reallocation Mechanism (MRE).

The MRE is a financial device to reduce hydrological risks in which the hydro units are mandated to participate, and the surplus from those that generate above their firm energy credit is transferred to those that generate below. It was created with the premise that the centralized operation creates problems, such as exposure to the spot market regardless of the agents' risk aversion and commercial commitments. Hence, the socialization of risks intends to reduce such exposure and take advantage of the portfolio effect from hydroelectric units located in different geographic regions. However, since 2013, the hydraulic units have gone through financial drawbacks when the total amount of energy physically produced by the MRE suppliers was regularly lower than the total amount of firm energy certificates. Under the argument that their financial exposure resulted from unpredictable and unmanageable factors, other than hydrology risks, the generators undertook several judicial disputes which created a billionaire liability, weakening spot market liquidity.

Once changed to a bid-based market, the premise of the MRE's would no longer prevail, implying the possibility of extinguishing it. The mandatory sharing of individual benefits in favor of a risk apportionment implies an efficiency disincentive. On the other hand, the idea of creating voluntary mechanisms to share risks and take advantage of the portfolio effect is highly recommended. In this context, nothing would impede that in the new competitive environment, the participants create, by their own will and initiative, mechanisms where different energy resources could complement each other and achieve better efficiency. In [79] they propose a risk-averse approach for an optimal portfolio, allocating renewable resource assets belonging to different companies resulting in fair and stable revenues. The benefits from the portfolio effect should be achieved through voluntary movements, comprising different generation technology besides hydro units.

From this perspective, the Nordics, New Zealand, and Colombia, also hydro-dominated systems and bid-based, do not adopt an explicit method for dealing with the hydrology risks. Among them, only Colombia allows different owners in the same river cascade and does not mandate mechanisms for managing such risks. As Colombia and other more mature markets do, we consider the procurement of derivatives in exchange platforms or forward bilateral agreements an excellent alternative to replace the MRE. Other markets such as the European and North American make available liquid exchanges with a wide range of derivatives to foster competition and address the specificities of the different generating resources.

5.2
Long-term Markets

The forward platforms liquidity is also seen as good practice in Brazil and it is pointed as a goal by CP 33. The recent enhancement of the forward platforms, including derivatives and the forward curve, is a good start for promoting liquidity, but they still do not provide a “reliable” forward curve and are limited to forward bilateral contracts. Brazil is ahead of Mexico and Chile, where all contracts are settled bilaterally, but it is behind the most liberalized, that offer at least one platform with financial and/or physical derivatives. MIBEL, for example, offer through its platform OMIP, specific products for solar and wind generation. The United Kingdom (which mostly relies in thermal generators), offer spark spreads where the agent can assume two separate positions in the underlying futures legs i.e. a long (short) position in Natural Gas Futures and a short (long) position in the Base Electricity Futures.

The increase of non-regulated consumers in the Brazilian market would help to enhance liquidity of the more mature markets. Currently, there is no regulatory impediment to reducing the minimum demand criteria of the regulated market. In fact, the ordinance [80] foresees the gradually opening of the non-regulated market. However, as advised in public consultation (CP) nº33/2017, the market opening without resource adequacy mechanism enhancement would intensify the cross-subsidy, overcharging regulated consumers. For that reason, CP nº33/2017 and the proposed bill PL 414/2021 suggest guidelines for the market modernization which should respect some order, to avoid problems such as the cross-subsidy. The unbundling of reliability and energy is suggested to correct this market asymmetry, allow a correct and organized market opening, and guarantee that the revenue from the reliability products is reduced, making it possible to adopt more frequent revisions. The MME indicates that will be at least two reliability products: firm energy and capacity, both procured in the centralized auction on behalf of every consumer with the costs shared between them. The energy contracts would only work as a hedge product, and the generators would not be limited in this criteria.

No consensus exists in terms of the resource adequacy mechanism to adopt, but the approach suggested by [26] would not be suited according to how the reforms are being structured in Brazil. They already defined that it will be at least two reliability products. Therefore, the quantity-based approach such as the reliability auction or reliability option are the remaining possibilities. Market power was perceived by [75] in Colombia's reliability option mechanism due to the combination of the two long-term products products (the forward contracts and the call option), creating incentives for the hydro units with high market share to manipulate scarcity conditions. Because Colombia is very similar to Brazil regarding its electricity matrix, this mechanism may not be suitable.

Assuming that Brazil will adopt the reliability auctions, some details should be taken care of, such as guaranteeing the participation of all capacity resources (including demand response and batteries), frequently review the reliability credits, and considering a combinatorial auction, as the current in Mexico, in order to procure the optimal set of units that attend both criteria jointly. Among the reliability auctions mechanisms observed in this work, the only reliability credit adopted was capacity, and they were reviewed yearly and *ex-post*, being an implicit incentive for performance. In the case of remaining with the *ex-ante* reliability credit evaluation, the regulator should also consider enhancing the planning models and reducing the horizon to estimate realistic contributions to the system safety.

6 Summary and Conclusions

In this work, we aimed to bring some light and new arguments towards the Brazilian wholesale electricity market modernization debate. We began defining some nomenclatures and typology to promote a common ground of concepts before presenting a critical analysis of the discussed market mechanisms. There are many ways of classifying a market accordingly to its organization, and it is usual to find different nomenclatures on the same features or same names for different definitions depending on the country or continent. Because this work intended to compare markets from different continents, it became essential to define a particular nomenclature that would embrace all the systems selected.

Subsequently, to better grasp the application of each mechanism adopted, an up-to-date overview of the markets' physical systems was given together with the market features that could be justified from the system's physical characteristic's optic. Finally, we brought the practices incorporated in markets with different maturities and physical structures to help us identify the strengths and weaknesses of the features applicable to the Brazilian market, given that some steps towards the modernization of the sector have already been taken. The Brazilian market is lagged behind the more sophisticated markets, and its critical matter is providing the right economic signals to market participants to achieve an efficient market outcome, attracting the technologies that would alleviate the system operational problems. Each market design overcomes its challenges differently according to its structure. Despite the variety of routes being taken, they can learn from each other's experiences, and especially for the least sophisticated markets, there is an opportunity to perceive the pros and cons of each mechanism, both in practice and in theory, and chose what adapts better to its reality, before making a structural change.

In summary, North and Latin America and New Zealand adopt integrated market models, while the European adopt the unbundled. The integrated markets diverge in terms of liberalization, being Chile, Mexico, and Brazil the most centralized ones, adopting a single-settlement cost-based approach. The cost-based markets can fog up price transparency due to the hidden costs from the lack of perfect information and global risk aversion, diminishing the market reliance on spot prices. However, if competitiveness cannot be assured, a bid-based market could face problems with market power. Justified by their low level of competitiveness, and physical aspects (hydro-dominance and transmission bottleneck), Chile, Mexico, and Brazil preferred to deal with the cost-based inefficiencies rather than face the uncertain consequences of a potential poorly designed market. However, many systems in similar conditions accomplished a well-functioning market with the bid-based approach. For example, New Zealand, the Nordics, and Colombia are great examples of hydro-dominated markets with effective bid-based markets. PJM proved that integrated multi-settlement markets with high granular prices are workable in large-size systems, and it can still provide long-term liquid markets. New Zealand is also a good example that even renewable-dominated systems can operate well under nodal prices.

Our analysis strongly indicates that the better way to have an efficient operation is by letting the players express their opportunity costs rather than having one central entity inferring their marginal costs and generation expectation. Nevertheless, when the system conditions are highly propitious to market manipulation, the step towards a more liberalized market should be carefully taken. For example, we observed that the intra-zonal congestion is substantial in the Brazilian system. Hence, we believe it should be dedicated special notice to this matter before migrating to a bid-based environment to avoid failures such as those observed in California. A possibility would be to implement some market features such as the nodal prices and multi-settlement clearing before the migration to the bid-based model, to postpone some regulatory burden regarding the market power mitigation tools. Also, the congestion rents could be allocated to alleviate the transmission system and mitigate further market power. Since the dispatch model already releases half-hourly and nodal prices, it should be no technical limitation to enhance the price signals in these dimensions.

Realistic, high frequency and granular prices lead to more volatility, making the enforcement of long-term markets essential to avoid abuses in short-term. The European markets are great examples of liquid and mature derivatives trading. Countries such as Germany offers a wide variety of products and exchanges to help agents deal with their peculiarities, reduce risks and prosper in the market. Additionally, the UK, MIBEL, and the American markets, make use of resource adequacy mechanisms to guarantee generation investment. Although this mechanism is suitable to attract investment, depending on the extension on delivery periods, and the way the reliability credits are calculated, it could result in a bias on the investment decision. The bias could result in either high spot prices or lack of system's firmness. The more is the revenue from resource adequacy, the more critical becomes this problem. From the markets analyzed, Brazil is the market with longest delivery periods on resource adequacy, and with the least frequent revision on reliability credits.

The way the modernization is being conducted, reliability and energy will be unbundled, and it seems that it will be at least two reliability credits: firm energy and capacity. The only market that follows a similar structure, procuring different products within an auction, is Mexico. In his framework, Mexico procures its products in combinatorial auctions, which we believe is a good practice since one source can offer more than one product, and the optimal procurement should consider all sources together. However, too many regulatory mechanisms to ensure resource adequacy with delivery longer than five years may weaken the price signal as the primary driver of expansion which tends to bias investment decisions and goes against the market principles.

Last but not least, it is important to keep in mind that even if achieving all "best practices" reported, the reform's necessity will not be over. According to the insertion of new technologies and policies, many details regarding each mechanism must be adapted if not changed. Hence, it is essential to implement regulatory rules that accommodate changes faster than today's to keep providing efficient economic signals to the market.

A
Additional Information

Selected Markets	Mechanism	Coverage	Reliability Credit (RC)	RC Evaluation Order	RC Evaluation Frequency	Obligation Period	Lag Period
Brazil	Electricity and Reliability Auction	Market-wide	Firm Energy	Ex-ante	5 years	1, 2, 15, or 30 years	Y-1, to Y-6
Chile	Reliability payment	Market-wide	Capacity	Ex-post	1 year	1 year	-
Mexico	Reliability Auction (Combinatorial)	Market-wide	Capacity	Ex-post	1 year	3 or 15 years	Y-1, Y-3
Colombia	Reliability Option	Market-wide	Firm Energy	Ex-ante	1 year	1, 5, 10, or 20 years	Y-1
Ontario	Reliability Auction	Market-wide	Capacity	Ex-post	1 year	1 year	Y-1
New Zealand	Strategic Reserve	Target	Capacity	-	-	-	-
PJM	Reliability Auction	Market-wide	Capacity	Ex-post	1 year	1 year	Y-3
CAISO	Reliability Obligation	Market-wide	Capacity	Ex-post	1 year	-	-
Nordics	Strategic Reserve	Target	Capacity	-	-	-	-
MIBEL	Reliability Payment	Target	Capacity	Ex-post	1 year	1, or 10 years	-
Germany	Strategic Reserve	Target	Capacity	-	-	-	-
UK	Reliability Auction	Market-wide	Capacity	Ex-post	1 year	1, 3, or 15 years	Y-1, Y-4

Table A.1: Resource Adequacy Mechanisms

Selected Markets	Nodal	Zonal	Single	Order	How ex-ante	Frequency	Mechanism
Brazil		✓		Ex-ante	1 day	Hourly	Dual from economic dispatch
Chile	✓			Ex-post	-	Hourly	Marginal unit from merit order curve
Mexico	✓			Ex-ante	15 min	Hourly	Dual from economic dispatch
Colombia			✓	Ex-post	-	Hourly	Marginal unit from merit order curve
Ontario			✓	Ex-post	-	5 min	Dual from economic dispatch
New Zealand	✓			Ex-post	-	30 min	Dual from economic dispatch
PJM	✓			Ex-ante	10 min	5 min	Dual from economic dispatch
CAISO	✓			Ex-ante	10 min	5 min	Dual from economic dispatch
Nordics		✓		Ex-ante	1 hour	Hourly	Uniform Auction
MIBEL		✓		Ex-ante	1 day	Hourly	Uniform Auction
Germany			✓	Ex-post	-	15 min	Weighted average of balancing services
UK			✓	Ex-post	-	30 min	Weighted average of balancing services

Table A.2: Settlement Prices

Selected Markets	Electricity Products in Exchange						Exchange		Electricity Products Centralized by the SO		
	Forward/Future	Option	Spread	Swap	Settlement[1]	Reference Price[2]	Name(s)	CCP	Forwards	Settlement	Reference Price
Brazil	✓				F(D)/F	RT	BBCE, B3		✓	F(D)	RT
Chile									✓	F(D)	RT
Colombia	✓				F	RT	Derivex	✓			
Mexico									✓	F(D)	RT
Ontario	✓				F	RT	ICE, NYMEX	✓			
New Zealand	✓	✓			F	RT	ASX	✓			
PJM	✓	✓			D/F	DA/RT	ICE, NYMEX, Nodal	✓			
CAISO	✓	✓			D/F	DA/ID/RT	ICE, NYMEX, Nodal	✓			
Nordics	✓	✓	✓		F	DA	Nasdaq, EEX	✓			
MIBEL	✓	✓	✓	✓	D/F	DA	OMIP	✓			
Germany	✓	✓		✓	F	DA	ICE, Nasdaq, EEX, OMIP	✓			
UK	✓		✓		D/F	Future	ICE, Nasdaq	✓			

Table A.3: Electricity Derivatives

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