WORKING PAPER · NO. 2026-03

Renewable Energy Expansion: Key Challenges and Emerging Opportunities

Koichiro Ito

JANUARY 2026

THE UNIVERSITY OF CHICAGO
BECKER FRIEDMAN INSTITUTE FOR ECONOMICS

5757 S. University Ave.
Chicago, IL 60637
Main: 773.702.5599
bfi.uchicago.edu

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January 2026
JEL No. Q40, Q50

ABSTRACT

The global expansion of renewable energy is key to addressing climate change. After a decade of dramatic cost reductions—especially for solar photovoltaics and wind—renewables now approach cost parity with fossil generation. While this cost reduction has led to a steep increase in solar and wind power in several countries, the global share of solar and wind generation remains modest—approximately 15% as of 2023. This article reviews recent economic studies and identifies three central challenges and corresponding opportunities for scaling up renewable energy—underdeveloped regulatory and market design, insufficient intertemporal market integration, and inadequate spatial market integration. The insights from this review highlight effective ways to accelerate the global transition to renewable energy.

Koichiro Ito
University of Chicago
Harris School of Public Policy
and NBER
ito@uchicago.edu

1 Introduction

Expanding renewable energy in a cost-effective and efficient manner is among the most pressing challenges in mitigating climate change. The electricity sector, along with transportation, is one of the largest contributors to global greenhouse gas (GHG) emissions.[1] Furthermore, as a large share of the transportation sector is expected to undergo electrification in the near future, decarbonizing electricity generation becomes even more essential to mitigating climate change.

Until recently, the large-scale expansion of renewable energy was considered impractical primarily due to its high cost. A decade ago, the levelized cost of energy (LCOE) for renewables—especially solar power—was significantly higher than for other technologies, such as thermal, nuclear, and hydropower. However, the LCOE for renewables has fallen dramatically over the past decade. Data from Davis, Hausman and Rose (2023) show that the LCOE for solar was nearly \$500 per MWh in 2010, declining to \$36 per MWh by 2020. In 2020, the LCOEs for combined-cycle natural gas and wind were \$37 and \$38 per MWh, respectively, indicating that these three technologies now have comparable costs.[2]

While this cost reduction has led to a steep increase in solar and wind power in several countries, the global share of solar and wind generation remains modest—approximately 15% as of 2023 (Figure 1). There are many reasons why some countries have successfully expanded renewable energy while others continue to struggle. Rather than attempting to cover all possible explanations, this article focuses on three key challenges that many countries face in expanding solar and wind energy.[3][4]

The first challenge is *underdeveloped regulatory and market design* for accommodating high

[1]Electricity and heat production accounted for 25% of global GHG emissions in 2010, while transportation contributed 14% (IPCC, 2014). In the United States, 29% of GHG emissions in 2019 came from the transportation sector, and 25% from the electricity sector (EPA, 2020).

[2]Note that the LCOE of natural gas depends heavily on gas prices, which vary across locations and over time, and similarly, the LCOE of solar depends on solar irradiation, which varies across regions. The estimates presented here are based on data from the United States.

[3]In this article, I use "renewable energy" to refer specifically to solar and wind energy, excluding hydropower and geothermal sources.

[4]Complementary survey articles that cover additional challenges related to renewable energy expansion include Joskow (2019) and Fabra (2021).

penetration of renewables in electricity markets. Historically, energy markets and related regulations were designed for non-renewable electricity sources such as thermal, nuclear, and hydro power. However, renewable plants differ significantly from conventional ones. For example, electricity generation from renewables is intermittent—solar and wind power exhibit second-to-second volatility due to natural fluctuations in sunlight and wind. Additionally, solar and wind are non-dispatchable because their generation depends on environmental conditions. Therefore, reforming existing regulatory frameworks and market rules could facilitate the adoption of renewables. I will illustrate this issue using prominent examples from the economics literature.

The second challenge is *insufficient intertemporal market integration*. The intermittency and lack of dispatchability of solar and wind power could be addressed if large-scale energy storage becomes cost-effective. With such storage, solar and wind energy could be stored and then used as a non-intermittent, dispatchable resource. Storage would allow electricity markets to be integrated over time, enabling renewable energy to be dispatched during peak-demand hours. The key question is whether large-scale energy storage can become economically viable. I will discuss this issue by summarizing recent findings in the economics literature.

Finally, the third challenge is *inadequate spatial market integration*. In many countries, a major bottleneck to expanding renewables is the lack of transmission capacity linking renewable supply sources with demand centers. The underlying issue is similar to the regulatory and market design problems described earlier. Existing transmission infrastructure was not built with renewables in mind. Conventional power plants, such as thermal facilities, could be located relatively close to demand centers (e.g., large cities), requiring only limited transmission networks. In contrast, the most efficient sites for generating solar and wind energy are often located far from population centers. The resulting lack of spatial integration leads to substantial curtailment of renewables and extremely low or even negative local wholesale market prices in many electricity markets. These two outcomes disincentivize renewable energy investment. I will explore this issue by presenting the general problem and discussing recent developments in the United States and Chile.

2 Underdeveloped regulatory and market design

The first challenge faced by many countries involves underdeveloped regulatory frameworks and market designs that are not suitable to accommodate high penetration of renewable energy in electricity markets. Existing regulatory rules and market structures were originally created to support large-scale, centralized, and dispatchable power generation—such as coal-, gas-, and nuclear-fired plants. In contrast, renewable energy sources, particularly when deployed at scale, tend to be variable, non-dispatchable, and often decentralized.

Although numerous countries are undertaking efforts to reform regulatory frameworks and market mechanisms to better integrate renewables, these reforms have generally lagged behind the rapid pace of cost declines and technological advancements. In this section, I present two illustrative examples to demonstrate how outdated regulatory and market designs could impede the expansion of renewable energy.

2.1 Interconnection queue problem

The issue of *interconnection queues* in the United States offers a highly illustrative case in point. To connect to the grid, new projects are required to complete exhaustive technical studies, pass a battery of reliability and system impact analyses, and secure agreements for grid reinforcement or network upgrades. These processes, while necessary for system security, are often marred by bureaucratic inefficiency, lack of standardization, and disputes over cost allocation.

Many renewable power plants are currently waiting for approval to connect to the grid, with the average wait time extending to five years as of 2023. This prolonged waiting period for connection approval is often referred to as the interconnection queue problem. This delay is due to a slow-moving regulatory process, and while the FERC and other market operators are working to address the issue, it remains a significant source of uncertainty for renewable energy projects.

As of 2023, around 2,600 GW of capacity—more than twice the size of the entire U.S. power plant fleet—was waiting in the queue (Rand et al., 2023). This backlog is likely to delay the pace of renewable investments and could impact the forecasts of renewable expansion.

Johnston, Liu and Yang (2023) analyses the industrial organization of this problem. They find that a long interconnection queue increases the average waiting time, and high interconnection costs are a key factor in a generator's decision to withdraw. Their simulations indicate that reducing waiting times can significantly increase completions. An alternative queuing mechanism can therefore increase completed capacity by removing certain generators to reduce congestion.

Many electricity markets in the United States have acknowledged this issue and are currently undergoing regulatory reforms. For instance, the Midcontinent Independent System Operator (MISO) has proposed several measures, including limiting interconnection queue capacity and increasing entry fees and withdrawal penalties. However, it remains to be seen whether these reforms will effectively reduce the waiting time for new renewable energy projects to come online.

2.2 Wholesale market design

Another major challenge lies in the design of wholesale electricity markets. Auction rules in these markets were initially developed during a period of low renewable penetration, when most market participants were dispatchable, fossil-fuel-based generators. As the share of renewable generation has increased, many of these rules have become outdated and require reform to accommodate the characteristics of renewable energy sources.

A clear example is provided in Ito and Reguant (2016), which examines the structure of sequential electricity markets. Deregulated electricity markets typically consist of a day-ahead forward market and a real-time spot market. Most electricity production is scheduled in the day-ahead market, while the real-time market ensures balance between actual demand and supply.

Figure 2 illustrates the sequence of market operations in the Iberian electricity market. On the day prior to delivery ($t-1$), producers and consumers submit bids for each hour of the next day. A uniform-price auction determines hourly prices in the day-ahead market, which plans for nearly all expected electricity demand. After market clearing, the system operator identifies potential transmission congestion and may adjust initial dispatch schedules accordingly.

Following this, the first intraday market opens on day $t - 1$, allowing market participants to adjust their positions for each hour of day t. Suppliers can reduce commitments by buying electricity or increase commitments by selling additional quantities. Multiple intraday markets follow, each using a uniform-price auction. The number of adjustment opportunities depends on the delivery hour—fewer for early-morning hours, more for later hours.

After the final intraday market closes (e.g., at 4 p.m. on day t), no further adjustments can be made. Deviations from scheduled quantities are penalized based on market imbalances and the willingness of others to compensate. In general, firms respond to these penalties by minimizing final deviations, so this analysis assumes incentives for deviation minimization are in place.

While sequential markets offer important benefits—such as enabling firms to manage uncertainty in demand and supply—Ito and Reguant (2016) find empirical evidence of arbitrage behavior by wind farms. Specifically, some wind producers systematically oversold their positions in forward markets and repurchased electricity in intraday markets (Figure 3). Although price arbitrage may enhance market efficiency in theory, this behavior introduces unnecessary uncertainty into supply forecasts, complicating the system operator's task of balancing supply and demand.

Partly in response to this issue, the regulator implemented a market rule change in 2013.[5] Beginning in January of that year, the electricity price received by wind farms was decoupled from the sequential market prices. This policy effectively eliminated incentives for arbitrage. Exploiting this quasi-experiment, the study tests whether smaller ("fringe") wind farms ceased arbitrage behavior after the reform. Figure 3 shows consistent overselling by fringe wind farms during 2010–2012, with a marked absence of such behavior in 2013, despite comparable levels of wind production in 2012 and 2013. This confirms that the reduction in arbitrage was not due to changes in output.

The findings in Ito and Reguant (2016) exemplify broader changes in wholesale electricity markets that can facilitate the integration of renewable energy. As the structure of electricity supply evolves, it is important to reconsider which market designs are most appropriate for incorporating new technologies.

[5]The primary objective of this policy change was to limit exposure of wind producers to high market prices.

3 Insufficient inter-temporal market integration

A defining characteristic of wind and solar energy is their intermittency and lack of dispatchability. Unlike fossil generators, which can be ramped up or down in minutes or hours, renewable output is determined by natural variability at timescales ranging from seconds to seasons. While geographic and technological diversity can reduce some variability, it cannot wholly eliminate the risk of surplus or scarcity relative to system demand.

Intermittency means that the supply of solar and wind electricity has to have second-to-second volatility in electricity generation due to the natural volatility in sunlight and wind. Intermittent electricity supply is challenging to electricity market operators because it negatively affects stability of the system. Likewise, solar and wind are non-dispatchable because the timing of their generation depends on the nature.

What would be a solution to the intermittency and lack of dispatchability of solar and wind power? Currently, the most promising solution is energy storage. If solar and wind energy can be stored at a large scale, energy storage can be used as a non-intermittent and dispatchable energy source. Storage would integrate electricity markets inter-temporally, allowing solar and wind energy to be dispatched in peak-demand hours.

For example, Arkolakis and Walsh (2024) shows an optimistic outlook for renewable energy expansion in the U.S. given the affordability of large-scale energy storage. Their finding suggests that the United States can have a rapid increase in solar and wind generation along with storage capacity, and as a result, power prices could fall between 20% and 80% by 2040 relative to 2024, driven by market forces rather than government interventions. This reduction in electricity prices, in turn, is projected to lead to a 2–3% real wage gain for U.S. workers.

The key question is whether large-scale energy storage can become cost-effective. While the cost trajectory for batteries up to date mirrors that of solar PV, with dramatic declines over the past decade, the further cost reductions in large-scale batteries within the next 15 years is uncertain. Arkolakis and Walsh (2024) show a variety of studies that have different cost forecasts. While some studies predict that the battery cost will be less than $10 per kWh by 2020, other studies forecast more moderate cost reductions in the next decade.

One piece of promising evidence is that large-scale energy storage is already unfolding in some countries, including Chile. Figure 4 shows the list of new power plants under construction in Chile as of August 2024 (Generadoras de Chile, 2024). The top four technologies include solar photovoltaic (53%), batteries (23.4%), wind (10.5%), and solar + batteries (7.6%). In this sense, the future scenario on the co-existence of renewable energy and large scale storage is already becoming a reality in Chile.

4 Inadequate spatial market integration

The third major challenge is *inadequate spatial market integration*. In many countries, a key obstacle to the expansion of renewable energy is the limited transmission capacity linking renewable-rich regions to major demand centers. This issue is fundamentally similar to the regulatory and market design challenges discussed earlier. Existing transmission infrastructure was developed primarily for conventional power generation and not designed to accommodate the geographic dispersion of renewable resources. Traditional power plants, such as thermal facilities, are typically located near demand centers (e.g., urban areas), thus requiring only relatively modest transmission infrastructure.

By contrast, the most productive sites for solar and wind energy generation are often situated far from population centers. This disconnect gives rise to two major problems associated with inadequate spatial market integration. First, when renewable energy generation exceeds local demand and cannot be exported, system operators are forced to curtail electricity generation to maintain grid stability, thereby discarding zero-marginal-cost and emissions-free electricity. Such curtailment is increasingly common across electricity markets, often accompanied by episodes of negative wholesale prices during periods of oversupply. For example, in 2017, California's wholesale market recorded negative prices 10 percent of the time (California ISO, 2018; Cicala, 2021). Wind generation is frequently curtailed in markets such as Texas and Spain, while Japan has experienced significant solar curtailment in the Kyushu region, which has limited transmission connectivity to the rest of the country. Second, because the marginal cost of renewable energy is effectively zero, regions with excess supply and no ability to export power experience suppressed local prices, discouraging further investment in renewable capacity.

4.1 Consequences of Insufficient Spatial Integration

The operational consequences of insufficient spatial integration are evident in recent power system statistics. Curtailment of renewable generation—where economically and environmentally desirable electricity is wasted due to transmission bottlenecks—has increased substantially. California curtailed over 4 percent of total utility-scale solar generation, while the Southwest Power Pool (SPP) region curtailed more than 10 percent of wind generation in 2022. These are neither isolated nor transient occurrences. Negative pricing—where generators pay the system to accept their output—has become a persistent feature in high-renewable electricity markets.

Transmission constraints also entail serious economic implications. Areas with high renewable potential are unable to fully capitalize on their comparative advantage, resulting in depressed local marginal prices, weakened revenue prospects, and diminished incentives for further investment. Millstein, O'Shaughnessy and Wiser (2023) document widespread local price collapses in the interior Midwest and parts of the Southwest, contributing to a "boom-bust" cycle in which waves of renewable investment are followed by underutilization and stranded assets when transmission upgrades fail to keep pace.

Despite the well-documented economic and environmental benefits of transmission expansion—including increased efficiency, enhanced reliability, and lower emissions—progress on major infrastructure projects has been sluggish. Political opposition, protracted permitting processes, legal conflicts over cost allocation, and local land-use resistance have delayed implementation, even where economic returns are demonstrably positive. As Cicala (2021) notes, The United States remains exceptional among industrialized countries in the fragmented nature of its electricity grid, with limited coordination between state and federal authorities. In contrast, nations such as Germany and China have at times achieved more effective national and supranational coordination of transmission planning.

Thus, resolving spatial integration challenges is not solely an engineering matter; it involves complex interactions among legal institutions, political dynamics, economic incentives, and public trust. The subsequent analysis highlights recent developments in Chile as a case in which institutional alignment and policy commitment have enabled meaningful improvements in spatial integration, yielding measurable benefits in the deployment and utilization of renewable energy.

4.2 Lessons from a Recent Success Case in Chile

To examine the role of spatial market integration in facilitating renewable energy expansion, Gonzales, Ito and Reguant (2023) study two major transmission upgrades in the Chilean electricity market. Prior to 2017, Chile's two primary electricity systems—Sistema Interconectado Norte Grande (SING) and Sistema Interconectado Central (SIC)—were completely separated, with no transmission interconnection. This separation posed a substantial barrier to renewable deployment, as the country's solar-rich regions near the Atacama Desert were isolated from demand centers in Santiago and from the mining industry located around Antofagasta.

To overcome this constraint, the Chilean government completed two major transmission projects: a new interconnection line between Atacama and Antofagasta in November 2017, and a reinforcement line between Atacama and Santiago in June 2019. The central objective of these investments was to connect high solar potential areas with major electricity demand centers. Atacama possesses abundant solar resources but limited local demand, while Antofagasta and Santiago represent significant demand hubs—due to industrial activity and residential and commercial consumption, respectively.

A core theoretical prediction in Gonzales, Ito and Reguant (2023) is that market integration leads to a convergence in wholesale electricity prices across regions. This prediction is tested in Figure 5, which displays commune-level average prices, calculated from hourly node-level wholesale prices weighted by hourly generation. Heat maps are shown for three periods: (1)

pre-interconnection, (2) post-interconnection but pre-reinforcement, and (3) post-reinforcement. The maps depict average prices at noon, a time typically associated with peak solar congestion in Chile's transmission network.

The left panel (pre-interconnection) reveals stark price differences, with Atacama exhibiting depressed prices due to unexportable solar surpluses. The middle panel indicates that the 2017 interconnection allowed solar power to flow northward, narrowing the price gap between Atacama and Antofagasta. However, price convergence between Atacama and Santiago was limited until the reinforcement line opened in 2019. The right panel shows that full nationwide price convergence occurred only after both infrastructure projects were completed.

Another key theoretical prediction in Gonzales, Ito and Reguant (2023) is that market integration induces *investment effects*—that is, beyond improving allocative efficiency, integration also stimulates new investment in renewable capacity. To assess this, the authors develop a structural model of power plant entry, leveraging Chile's relatively simple grid topology to enable tractable counterfactual analysis. Using the estimated model, they simulate various transmission expansion scenarios to evaluate their effects on solar investment, market prices, generation costs, and consumer surplus.

Their counterfactual simulations yield several important findings. First, ignoring the investment response, market integration alone increased solar generation by 10% compared to a scenario without integration, as curtailment would have otherwise constrained output. Second, this estimate substantially understates the true impact. Without market integration, solar investments would have been unprofitable due to suppressed prices in Atacama. By simulating the equilibrium investment level consistent with a positive net present value—based on Chilean government discount rates and investment horizons—the authors estimate that the full impact of market integration was a 178% increase in solar generation, compared to the 10% increase in the no-investment scenario.

These results underscore the importance of accounting for both gains from trade and investment effects in evaluating transmission investments. While the gains from trade alone reduced average generation costs by 7% during noon hours and by 3% across all hours, incorporating the investment effects raises these reductions to 18% and 8%, respectively. Furthermore, market integration plays a vital role in enabling price convergence across regions, thereby stabilizing revenue expectations and encouraging future renewable development.

Finally, the authors use their counterfactual results to conduct a cost-benefit analysis of transmission expansion. They find that excluding investment effects leads to a significant underestimation of the benefits of transmission upgrades. Including environmental externalities further increases the net benefit. Their analysis indicates that the investment in transmission infrastructure can be recouped within 7.2 years at a discount rate of 5.83%, yielding an internal rate of return of 19.7%.

5 Conclusion and Additional Key Issues

Although the sharp decline in renewable energy costs has spurred substantial growth in solar and wind power in several countries, the global share of solar and wind generation remains relatively modest—approximately 15% as of 2023. This article has reviewed three critical challenges that many countries encounter in scaling up solar and wind energy: underdeveloped regulatory and market design, insufficient intertemporal market integration, and inadequate spatial market integration. The insights from this review highlight effective ways to accelerate the global transition to renewable energy.

First, regulatory reforms in energy markets could play an important role in reducing frictions that hinder renewable energy expansion. For instance, current interconnection processes could be streamlined through standardized technical studies and expedited review pathways for low-risk projects. Clear and predictable rules for allocating the costs of grid upgrades are key to reduce investment uncertainty and prevent systemic delays.

Second, another key question is how to foster innovation and investment in large-scale energy storage technologies. As emphasized in this article, advancements in battery storage are not only pivotal for the electrification of the transportation sector but are also fundamental to resolving the intermittency and non-dispatchability challenges inherent in renewable energy sources.

Third, the recent experience in Chile illustrates the crucial role of spatial market integration in connecting renewable-rich generation regions with major demand centers. In most countries, investments in long-distance, high-capacity transmission infrastructure require sustained leadership and coordination across regional and national jurisdictions. Given the substantial long-term benefits associated with such investments, spatial integration has the potential to unlock important reforms in national energy strategies.

As described in the introduction, this article does not aim to comprehensively address all issues relevant to renewable energy expansion. Several particularly important topics are therefore not explicitly analyzed in this paper.

One such issue is the role of natural gas prices, which affect the profitability of renewable investment through wholesale electricity markets. Wholesale electricity prices are highly volatile and often track the marginal cost of gas-fired generation. As a result, renewable producers may be exposed to price fluctuations that are largely unrelated to their own production costs. For this reason, financial instruments such as long-term contracts—including both centralized contract markets and bilateral contracts—play a critical role in mitigating investment risk.

Another important issue concerns the long-run cost recovery of renewable investments. As renewables become the dominant generation technology, their near-zero marginal cost tends to drive wholesale prices toward zero during periods of production, creating substantial challenges for recovering fixed investment costs. Long-term contracts or capacity markets are often proposed as mechanisms to address this problem. However, both the research literature and policy discussions have yet to reach a consensus on what approaches are most effective.

Finally, challenges related to electricity storage extend beyond cost projections alone. Incentives to invest in storage depend not only on expected capital costs but also on expected revenues, which in turn hinge on how storage assets are operated. Storage operation depends critically on features of electricity market performance, including market structure and the potential exercise of market power (Andrés-Cerezo and Fabra, 2023). Moreover, whether renewables and storage act as complements or substitutes is central to understanding long-run deployment patterns. For example, Butters, Dorsey and Gowrisankaran (2025) show that storage and renewables can sometimes reinforce each other, but can also cannibalize one another when storage discharges and competes directly with renewable generation. This mechanism is particularly relevant in Chile, where complementarities between storage and solar generation appear to be especially strong and contribute to the high profitability of storage investments.

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Figures

Figure 1: Share of Electricity Production from Solar and Wind

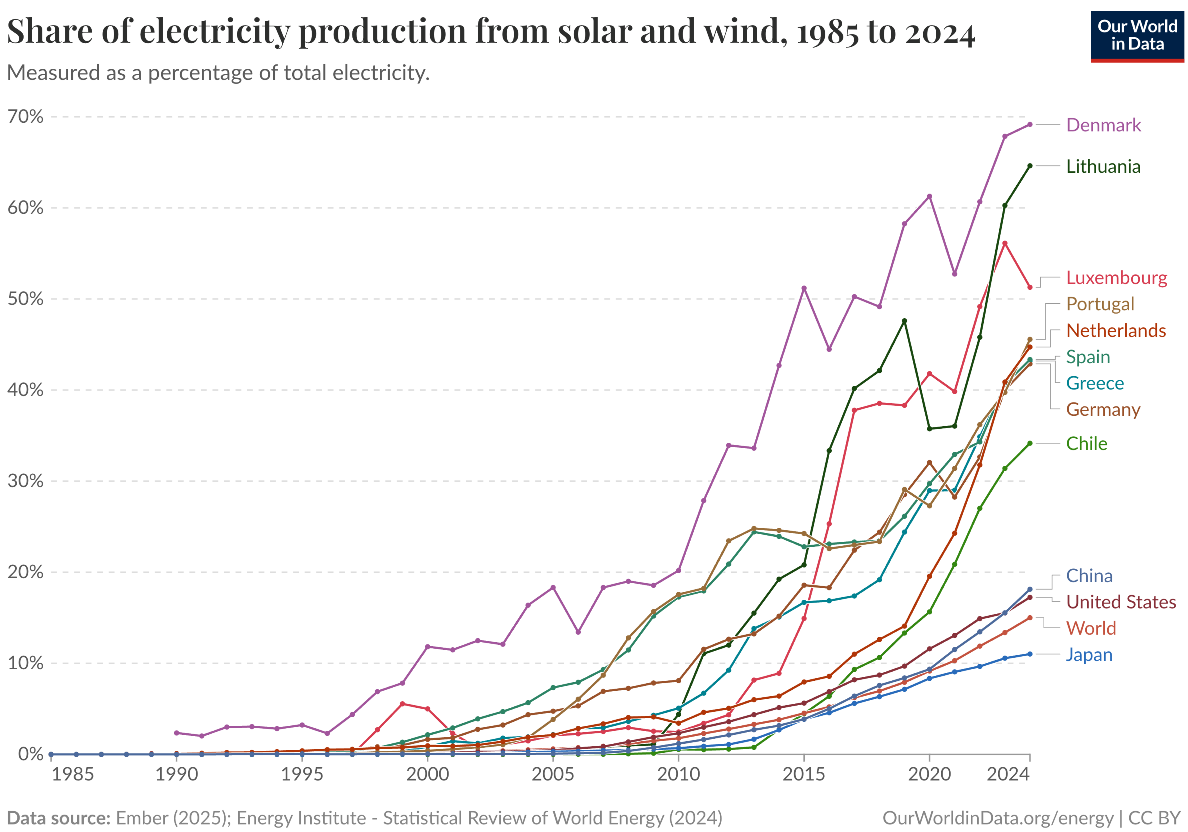
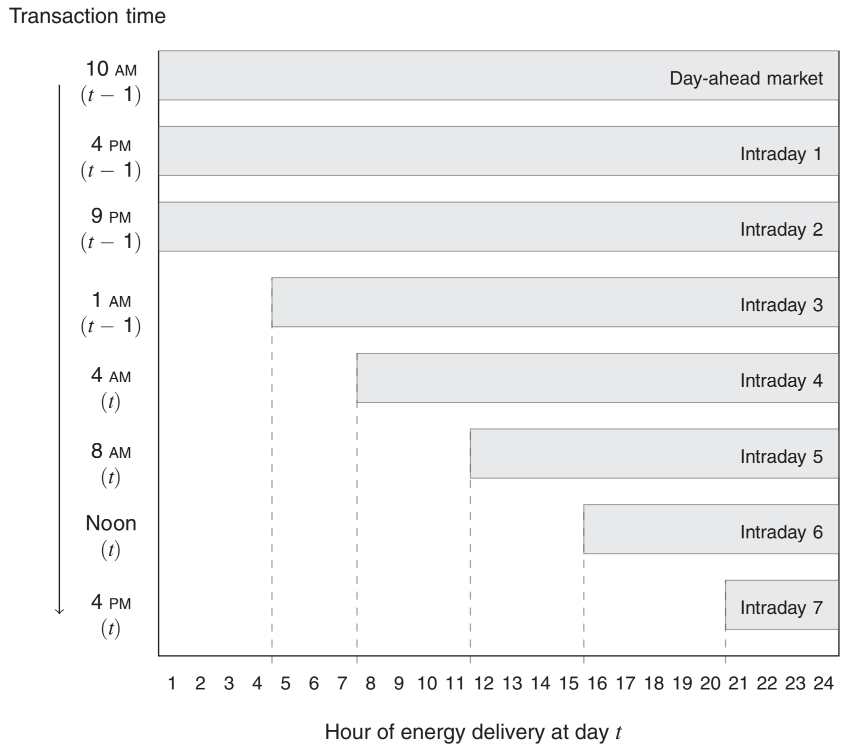
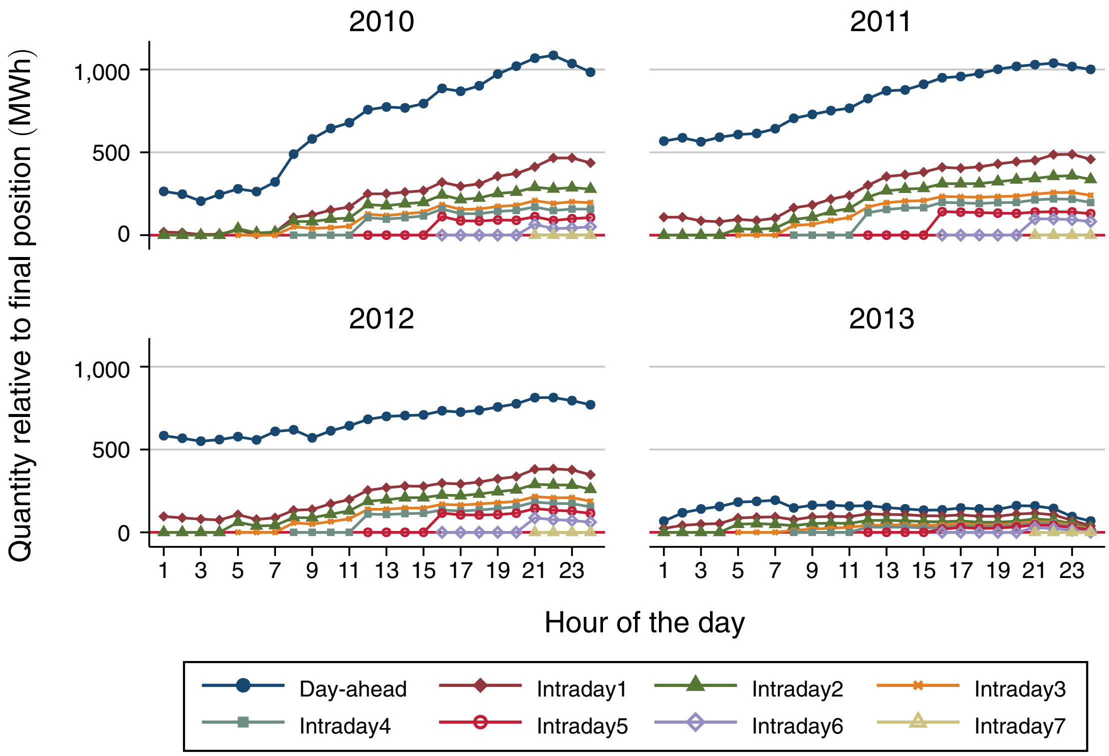


Figure 2: Sequential Markets in the Iberian Electricity Market



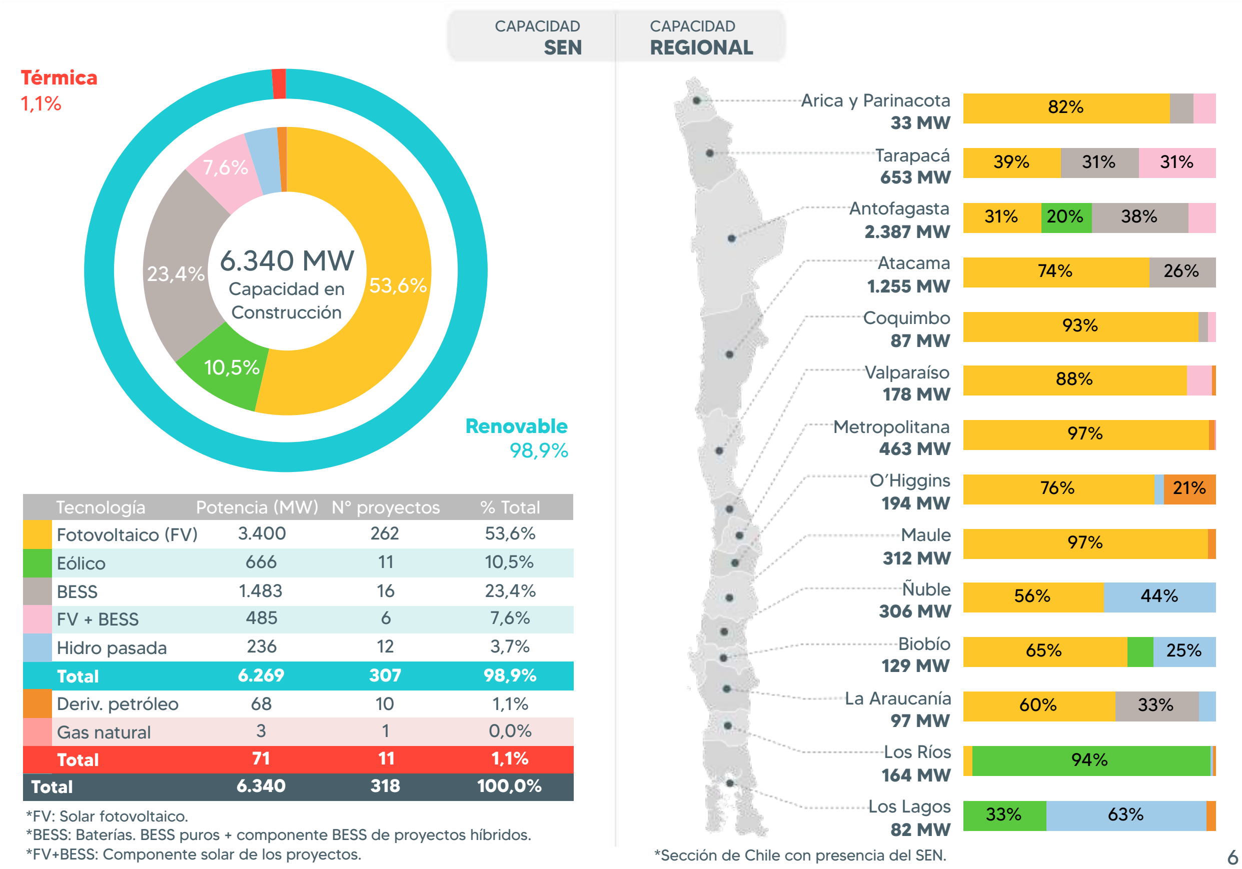
Note: Source: Ito and Reguant (2016).

Figure 3: Wind Farms' Overselling in Forward Markets in the Iberian Electricity Market



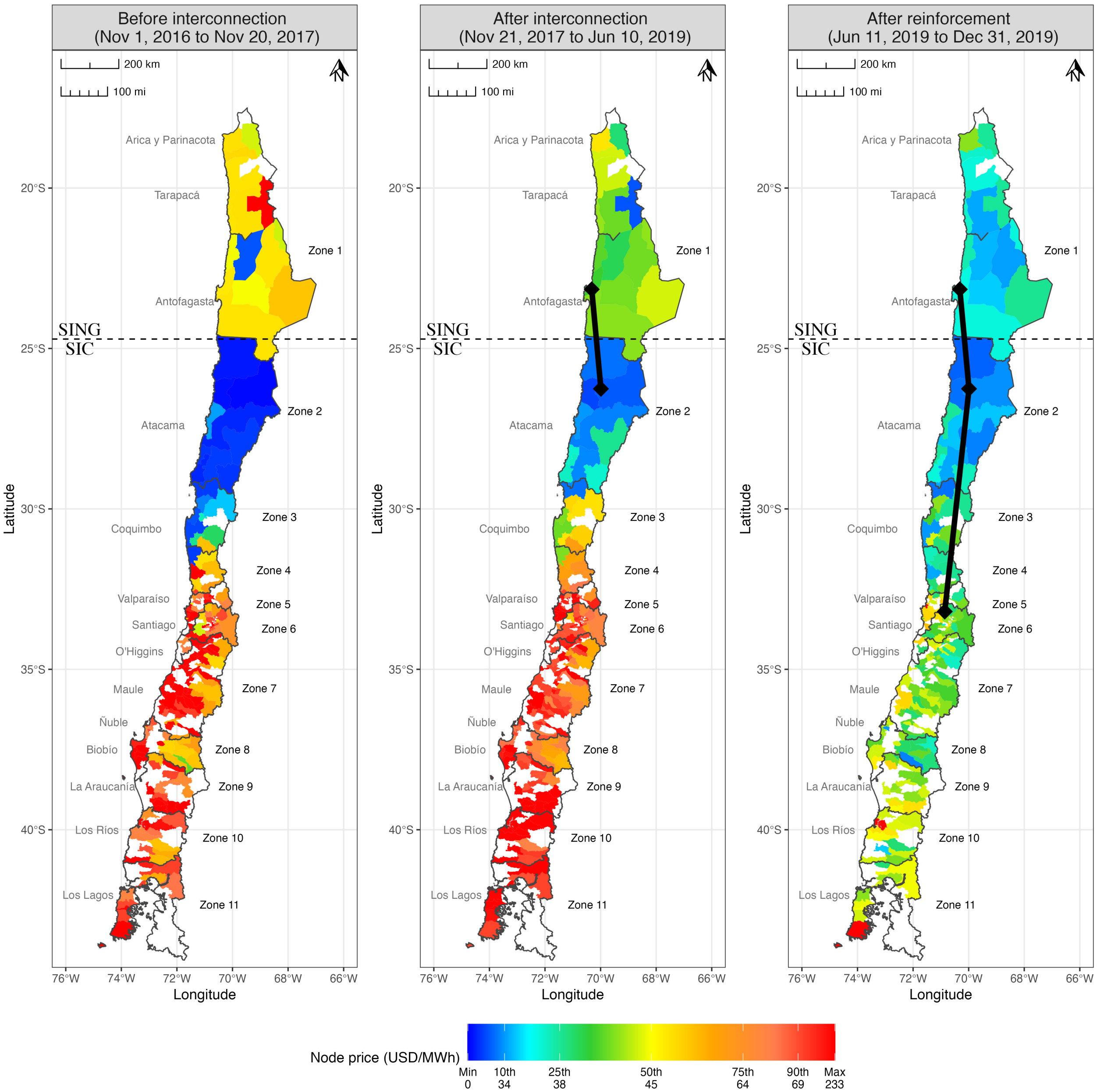
Note: Source: Ito and Reguant (2016).

Figure 4: List of New Power Plants under Construction in Chile in August 2024



Note: This figure shows the list of new power plants under construction in Chile as of August 2024 (Generadoras de Chile, 2024). The left-botom table shows new power plants under construction by technology: Fotovoltaico (solar photovoltaic), Eólico (wind), BESS (baterries), Hidro pasada (hydro), Derivados del petróleo (petroleum), Gas natural (natural gas), with columns: potencia (capcity), N proyectos (the number of projects). The map shows the capacity of new power plants under construction by technology and region.

Figure 5: Chile's Market Integration and Spatial Variation in Electricity Prices



Note: Souce: Gonzales, Ito and Reguant (2023).