The Value of Infrastructure and Market Integration: Evidence from Renewable Expansion in Chile*

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Abstract

Effective and economical expansion of renewable energy is one of the most urgent and important challenges of addressing climate change. However, many countries are facing a problem because existing network infrastructures (i.e., transmission networks) were not originally built to accommodate renewables, which creates disconnections between demand centers and renewable supply. We begin with a simple theoretical model that highlights why market integration plays a key role in renewable expansion in static and dynamic ways. Statically, market integration improves allocative efficiency by gains from trade. Dynamically, it incentivizes new entries of renewables plants. To quantify these theoretical predictions, we build a structural model of power plant entries and apply it to a recent change of market integration in the Chilean electricity market—two fully separated markets were integrated into one market in 2017. We find that market integration resulted in price convergence across regions, increases in renewable generation, and decreases in overall generation cost due to gains from trade. Furthermore, the dynamic impact quantified in our counterfactual simulations indicate that substantial amount of renewable entries would not have occurred in the absence of market integration. We show that ignoring this dynamic effect would significantly understate the benefits of market integration, including its impacts on allocative efficiency and renewable expansion.

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1 Introduction

Effective and economical expansion of renewable energy is one of the most urgent and important challenges of addressing climate change. The electricity sector generates one of the largest shares of global greenhouse gas emissions along with the transportation sector.[1] In addition, significant part of the transportation sector is expected to be electrified in the near future. Decarbonizing electricity generation is therefore critical to address climate change.

However, many countries are facing a challenge in expanding renewable energy because existing network infrastructures (i.e., transmission networks) were not originally built to accommodate renewables. Conventional power plants, such as thermal plants, were able to be placed reasonably close to demand centers (e.g. large cities), and therefore, minimal transmission networks were required to connect supply and demand. However, renewable energy, such as solar and wind, are often best generated at locations far from demand centers.

Two problems arise from the lack of market integration between renewable-intensive regions and demand centers. First, when renewable supply exceeds local demand, electricity system operators have to curtail electricity generation from renewables to avoid system breakdowns, even though this means that operators need to discard zero-marginal cost electricity from renewables. This curtailment indeed occurs in many electricity markets.[2] Second, because the marginal cost of renewable electricity is near zero, local market prices in renewable-intensive regions tend to be low or often becomes negative when it cannot be exported to demand centers. These two problems discourage new entries and investment in renewable power plants. Many countries started to realize these problems are among the first-order policy questions. For example, the Biden administration in the United States considers investment in transmission lines and renewable energy to be a key part of the infrastructure bill, currently proposed to be 1.75 trillion US dollars.

In this paper, we examine this question by providing theoretical and empirical analyses on the impacts of market integration on renewable expansion and allocative efficiency in wholesale electricity markets. We begin by developing a simple theoretical model that characterizes the static and dynamic impacts of market integration. In the static scenario, we assume that market integration does not affect producers' entry decisions. In this case, the value of market integration can be summarized by a conventional definition of gains from trade. Market integration allows lower-cost power plants to export and replace production from higher-cost power plants, which results in an improvement in allocative efficiency.

However, this conventional approach does not incorporate a potential dynamic impact of market integration. When producers can anticipate market integration, they have incentives to invest in new production capacity that will be profitable in the integrated market. This investment effect changes the supply curve of production, which results in an equilibrium that is different from the static case. Our model shows that this dynamic impact of market integration can

[1] Electricity and heat production accounts for 25% of the 2010 global GHG emissions and transportaiton acconts for 14% (IPCC, 2014). In the United Sates, 29% of the GHG emissions in 2019 comes from the transportation sector and 25% comes from the electricity sector (EPA, 2020).

[2] For example, wind power is often curtailed in Texas and Spain. Similar to Chile, Japan experienced large-scale curtailment of solar power in Kyushu region.

be substantial, and ignoring this impact could understate the impact of market integration.

With this insight, we empirically quantify these theoretical predictions by exploiting two large changes that recently occurred in the Chilean electricity market. Until 2017, two major electricity markets in Chile—Sistema Interconectado Norte Grande (SING) and Sistema Interconectado Central (SIC)—were completely separated with no interconnection between them. Recently, this separation has been recognized as an obstacle to expanding renewable energy because renewable-intensive regions (near Atacama desert) are located far north from demand-centered regions (near Santiago, the capital city). To address this problem, the Chilean government completed a new interconnection between these two markets in November 2017, and an additional extension transmission line in June 2019.

Not only do these expansions provide a unique research environment to apply our theoretical and empirical framework to study the impact of market integration, but the Chilean electricity market also offers another unique advantage in the comprehensiveness of its data. We are able to collect nearly all of the data relevant to market transactions, including hourly unit-level marginal cost, hourly node-level demand, hourly node-level market clearing prices, hourly unit-level electricity generation, and plant characteristics such as capacity, technology, year built, and investment.

We begin by presenting visual and statistical evidence of the static impacts of market integration on wholesale electricity prices, production, and cost. First, we show that the market integration in Chile resulted in price convergence across regions. Before the market integration, we observe that SING and SIC often had substantially different market clearing prices. In addition, within SIC, the Atacama desert region often became an isolated local market when its solar production exceeded the local demand and limited transmission capacity to other regions. We show that the market integration substantially reduced this spatial price dispersion by increasing prices in renewable-intensive regions and decreasing prices in demand centers.

Second, we investigate the static impacts of market integration on electricity production and cost. Consistent with our theoretical prediction from grains from trade, we find that the market integration allowed lower-cost power plants, including renewables, to increase their production, which replaced production from higher-cost plants. We find that the market integration resulted in a decrease in the cost of electricity generation per megawatt hour.

Third, we examine how the market integration affected new entries of renewable capacity. We find that a rapid growth in renewable capacity started right around the first *announcement* of the market integration in 2015, which was two years before the completion of the transmission line construction in 2017. In addition, we find that the node prices in renewable-intensive regions were near zero during this rapid increase in renewable capacity and increased to a profitable level for renewables only after the market integration. This evidence suggests that renewable investors made their investment decisions based on the *anticipation* of the market integration. This evidence also suggests that the static analysis, which ignores the potential impact on investment in new generation capacity, could understate the impact of market integration, as it is suggested by our theory.

To investigate the potential dynamic impacts of market integration, we build a structural model of power plant entries. In the model, investors consider investment for a new power plant based on the expected value of long-run profit from the investment. The net present value of investment depends on profit from subsequent years. A key element to the future expected profit is transmission constraints from its local region to other regions. The attractiveness of the Chilean market is that its simple geography makes the network model tractable and makes it feasible to conduct counterfactual analysis. We simulate a few counterfactual policies on transmission capacity expansion to examine each policy's impact on capacity investment in renewables, node prices, profits, and consumer surplus.

Our counterfactual simulations reveal several findings. First, our static result suggests that the market integration in Chile increased 17% of solar generation relative to the counterfactual case with no market integration. This is because in the absence of market integration, the system operator would have had to curtail excessive amount of power from solar due to transmission constraints. Second, this number still understates the impact on solar investment because substantial amount of solar investment would have become unprofitable without market integration due to low market prices. We simulate the market equilibrium to find the maximum level of solar capacity investment that could be positive in the net present value, given the discounted rate and duration of investment used by the Chilean government's public infrastructure projects. Our dynamic result suggests that the full impact of market integration on solar generation was a 45% increase in solar generation, as apposed to the 17% increase if we ignore this dynamic impact.

Our results indicate that both of the static and dynamic impacts of market integration are important factors in the evaluation of transmission investment. In our context, we find that the static effect itself resulted in 10.1% and 4.9% reductions in electricity generation cost per megawatt hour in hour 12 (a solar-intensive hour) and all hours, respectively. If we incorporate the dynamic effect on solar investment, these reductions in generation cost are 13.6% and 6.3%. Our simulation results also indicate that both of the static and dynamic impacts play key roles in the price convergence across regions.

Our findings provide important implications for energy policy in many countries. For example, the Biden administration in the United States considers the investment in transmission lines and renewable energy to be a key part of the infrastructure bill, currently proposed to be 1.75 trillion US dollars. Our theoretical model and empirical evidence from Chile provide several key implications on the design of the new transmission infrastructures in the US electricity markets.

Related literature—Our study builds on three strands of the literature. First, several earlier studies on wholesale electricity markets develop theoretical models on the impacts of transmission expansion (Bushnell, 1999; Joskow and Tirole, 2000; Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2005). Notably, theoretical models in these studies often start with a hypothetical example of two disconnected electricity markets—"North" and "South"—and consider the integration of these two markets. The grid expansions in Chile provide an empirical analogue to these hypothetical settings, which allows us to test predictions from these theoretical models. Another contribution of our study is that incorporate a dynamic impact of market integration to our model. We highlight that the dynamic impacts on power plant entries and investment can be a key part of the impact of market integration, which has been understudied in the literature.

Second, our paper is closely related to Mansur and White (2012) and Cicala (Forthcoming), which study how the introduction of market-based dispatch mechanisms affected allocative efficiency in the US electricity markets. While our paper benefits from insights from this literature, our research question is different in two folds. First, what we study is the impact of market integration by itself, keeping the dispatch mechanism unchanged. In our setting, the two separated markets in Chile had the same dispatch mechanism before the integration, and this mechanism did not change after the integration. This allows us to focus on the effects of market integration by itself, keeping the dispatch mechanism unchanged. Second, previous studies in this literature generally focus on the allocative efficiency in a static sense by considering the set of power plants fixed. Our paper explicitly considers both of the static and dynamic impacts of market integration by incorporating a dynamic impact on power plant entries.

Third, our project relates to recent studies on the role of transmission expansion in renewable energy policy. For example, Fell et al. (2021) examine how transmission congestion alters the environmental benefits provided by renewable generation. They find that alleviating transmission congestion resulted in an important environmental benefit by letting production from renewable plants replace production from thermal power plants near demand centers. Our study contributes to this literature in two ways. First, we show how market integration helps the economic benefit of renewable energy (i.e., its ability to generate electricity with zero marginal cost) spread across the entire electricity system through price convergence of local market prices. Second, we show that both of the static and dynamic effects are important in the evaluation of market integration because the dynamic impact in the form of plant entries create substantial additional gains in allocative efficiency and environmental benefits of renewable energy.

2 Theoretical Framework

Our goal is to understand the static and dynamic benefits of integrating markets, and how to recover them from data. To understand the challenge, it is useful to provide some intuition with a stylized example, which is represented in Figure 1. Imagine there are two regions, North and South, which are operating in autarky. The North region has lower costs. Equilibrium prices in autarky are given by $p^N < p^S$. In the static model, we assume that market integration does not affect renewable investments. In this case, the equilibrium from integrating markets with full trade is given by p^*. Costs on average fall (gains from trade), prices in one region (weakly) go up, and prices in the other region (weakly) go down. When compared to the outcomes under autarky, the gains from trade are given by the classical triangle marked in dots, which can be compared to the costs of building the line for a full cost-benefit evaluation.

[Figure 1 about here]

Imagine now that the Northern region is also the one with the best available solar resources. In the absence of a transmission line between North and South, such resources might not be profitable, but they would be attractive if the two regions were interconnected. If the line is expanded, new investment enters the market in the anticipation of the profitable environment. In Figure 1, we represent the equilibrium outcome after renewable plants are built in the North. Under full trade, the transmission line is expanded and the equilibrium price p^{**} goes down even further. The cost savings from this new equilibrium are described by the shaded area. To get at the full dynamic gains from trade, one would need to compare these benefits to the costs of building the line and the costs of the solar investment.

From an empirical perspective, it is useful to compare the costs of production before and after the transmission line is expanded. From Figure 1, and in the absence of solar investment, the benefits from the expansion should clearly identify the static gains from trade. In a model without frictions, incremental investment (the causal part of the investment) happens exactly when transmission is expanded, and thus the dynamic gains from trade can also be identified. However, in the presence of frictions, the timing of expansion might not coincide perfectly with investment. Consider a situation in which investors enter the market before the transmission line is fully developed in anticipation of the change, as in our application. Under such a scenario, a comparison of the "before-and-after" market outcomes could lead to the conclusion that the static gains from trade equal the larger shaded triangle. This calculation will understate the gross cost savings but it would also miss to account for the fact that solar investments would not have been profitable during the "before" period alone.

More generally, we expect the static approach to underestimate gross cost savings in the presence of differential timing. Note that this is also true if investment were delayed, as cost savings would not include any dynamic impacts in the event window. When it comes to price differences, the static approach will overestimate the impacts of the transmission line on price convergence in the presence of anticipated investments as long as $p^N < p^S$. Early investments will increase such a price difference, which will tend to converge after expanding the grid. Price reductions will be generally understated. If investments are delayed, the new price would be p^* as opposed to p^{**}, understating price reductions. The price reduction will also be understated in the presence of anticipated investment, as early solar investment tends to depress average prices in the "before" period.

To show these economic predictions more formally, we derive the equilibrium equations under a stylized model with linear marginal cost functions that we can solve in closed form. Assume there are two regions $r = \{N, S\}$ with demands $D^N \leq D^S$ and marginal cost functions $C^N(q^N) = \beta^N q^N$ and $C^S(q^S) = \beta^S q^S$, where q^N and q^S represent non-solar production in each region. For simplicity, consider the case in which $\beta^N \leq \beta^S$ so that under autarky $p^N \leq p^S$, as in Figure 1. We will compare the equilibrium under market integration (full trade) and autarky (no trade).

In autarky, the equilibrium is trivial and given by the intersection of the marginal cost curve and demand.

$$p^N = \beta^N D^N,\ q^N = D^N,\ p^S = \beta^S D^S,\ q^S = D^S.$$

Define total demand as D. In the absence of solar investment, equilibrium outcomes under full trade are given by:

$$p^* = \frac{\beta^N \beta^S}{\beta^N + \beta^S} D,\ q^N = \frac{\beta^S}{\beta^N + \beta^S} D,\ q^S = \frac{\beta^N}{\beta^N + \beta^S} D.$$

Importantly, we also consider endogenous investment in solar in the presence of market integration. Assume there is some cost to solar production, c, which can only be built in the North region.[3] For simplicity, assume $p^N < c < p^*$, so that investment only occurs under market integration. We also assume that entry of solar follows a zero profit condition. In this new environment, the equilibrium solar production becomes,

$$q^{solar} = D - \frac{\beta^N + \beta^S}{\beta^N \beta^S} c.$$

Intuitively, solar covers any demand not produced by the regions at price $p^{**} = c$, which becomes the equilibrium price under full trade.[4]

If investment is anticipated, but market integration has not yet occurred, the equilibrium is modified also under autarky. Taking q^{solar} as given, the autarky equilibrium with anticipated investment becomes,

$$p^N = (1 + \frac{\beta^N}{\beta^S})c - \beta^N D^S,\ q^N = \frac{\beta^N + \beta^S}{\beta^N \beta^S} c - D^S,\ p^S = \beta^S D^S,\ q^S = D^S.$$

The price and non-solar production in the North will be smaller in this new equilibrium with anticipation, while prices and production in the South remain at the same level in autarky.

Armed with this basic model, we show the following observations.[5]

Observation 1. *In the presence of investment anticipation or delay,* ***gross cost savings*** *from a grid expansion will be underestimated around the event window. Furthermore,* ***net cost benefits*** *accounting for the investment costs of solar will be*

- *underestimated if expansion is delayed, and*
- *overestimated if expansion is anticipated but its investment costs ignored.*

[3] Solar production involves mostly fixed costs. The cost c is intended to capture the strike price at which solar panels are profitable.
[4] We assume that c is such that solar investment is at an interior solution, i.e., $q^{solar} \geq 0$, as implied by $p^N < c < p^*$.
[5] Most of our results should be true under quite general conditions, but our proofs are based on the stylized cost curves in this basic model. We plan to extend the results to clarify if the linearity assumption matters for some of our predictions.

Visually, it is clear that gross cost savings are largest when the full shaded area is considered.[6] In the presence of delayed investments, gains from trade realized around the event window are only equal to the static gains, which are by construction smaller. If investment is anticipated, gains from trade only equal the triangle expanding the quantity beyond autarky, but miss the cost savings induced by the solar expansion in the North.

Observation 2. *In the presence of investment anticipation or delay,* ***price reductions*** *from a grid expansion will be underestimated around the event window.*

It is easy to see that with investment anticipation, prices before market integration will tend to be lower than without anticipation, due to the depressing effect of solar production. Therefore, price reductions will be less salient if solar investment has already occurred. In the presence of investment delays, the key is to show that price reductions are larger in the dynamic equilibrium than in the static one with no solar investment. This is again due to the depressing effects on prices from solar entry, which only occur in the dynamic case.

Observation 3. *In the presence of investment anticipation or delay, reductions in* ***regional price differences*** *(price convergence) will be*

- *overestimated in the presence of anticipation,*
- *correct in the presence of delayed investment as long as prices converge both with and without investment. Otherwise, price convergence will be overestimated.*

Prices in the North are depressed in the presence of anticipation of investments, as shown in Figure 1 when comparing p^N to $\hat{p}^N$. Therefore, the price gap in prices $p^S - \hat{p}^N$ is overstated. If investment is delayed but prices converge, then there is no bias in the case of delayed investments. However, in the presence of transmission line bottlenecks, price convergence will be overstated. As can be seen from Figure 1, there is more trade in the presence of solar investment (e^{**}) than without it (e^{*}). Therefore, if the price gap does not go to zero, price convergence will be higher when the cost curves between the two regions are more similar (static curves).

3 Background and Data

In this section, we describe institutional details about the Chilean Electricity Market and data to be used for our empirical analysis.

[6] See Appendix for mathematical proofs of all results.

3.1 Market Integration in the Chilean Electricity Market

In Figure 2, we summarize the recent market integration of the Chilean Electricity Market. Prior to November 2017, the electric power grid in Chile was organized in two main systems—Sistema Interconectado del Norte Grande (SING) in the northern region and Sistema Interconectado Central (SIC) in the central-southern region. There was no interconnection between these two systems, and each system was dispatched fully separately.

[Figure 2 about here]

In November 2017, these two systems were connected for the first time, with a double circuit 500kV transmission line with a firm capacity of 1500 MW. This interconnection connected the southern part of SING and the northern part of SIC to integrate the two systems. The integrated new system—Sistema Electrico Nacional (SEN)—consists of over 99% of the installed capacity for the country.[7]

In June 2019, this interconnection was extended by another double circuit 500kV transmission line that connected the northern part of SIC (Atacama desert region) and southern part of SIC (Santiago metropolitan region). In this paper, we use "interconnection" to refer to the interconnection built in 2017 and "reinforcement" to refer to the extension line built in June 2019. As we show in our analysis below, both of the interconnection and reinforcement played key roles in integrating the Chilean electricity market.

Long-distance transmission investment involves policy decisions, permit acquisitions, and major construction, all of which can take considerable time. Therefore, it is important to recognize that market players may be able to anticipate new transmission lines long before they are built, which may influence their decisions regarding construction of new power plants. It is thus critically important to factor this anticipation in the analysis of the long-run impacts of such investment.

In the case of the Chilean integration, the 2017 interconnection was likely anticipated as far as 3 years in advance. According to policy documentation, Chile passed a modification to the "General Electric Services Law" on February 7 in 2014, which promoted the idea of the interconnection of SING and SIC in the near future. The construction of the interconnection began in August 2015. Our empirical analysis therefore aims to incorporate the potential anticipation impacts on the investment in new power plants.

3.2 Cost-Based Dispatch and Pricing in the Spot Wholesale Electricity Market in Chile

Similar to other Latin American countries, Chile uses cost-based dispatch to clear demand and supply in its spot market. Everyday generators submit information on their marginal costs—including variable fuel costs, variable non-fuel costs, and start-up costs—to the Load Economic Dispatch Center (CDEC), which is the Independent System

[7] The remaining 1% is served by two other isolated systems as we summarize it in Figure 2

Operator (ISO) in Chile. The CDEC uses these costs, demand, and their network model to determine least-cost dispatch under transmission constraints.

The lowest cost dispatch means that the ISO ranks power plants from those with lower marginal costs to those with higher marginal costs and decide a set of power plants that can meet demand with the overall lowest cost that is possible under transmission constraints.

Therefore, the resulting spot market price is equal to the marginal cost of the most expensive unit of generation in use. In the presence of transmission constraints between regions, the spot prices can differ across regions. The most spatially desegregated price points are called nodes, and the CDEC publishes the hourly spot prices at the node level.

This cost-based dispatch mechanism is different from bid-based dispatch, which is a common dispatch method in many developed countries including the United States. In bid-based dispatch, power plants submit their supply bids in an auction market. Their bids do not have to be equal to their marginal costs. In contrast, in cost-based dispatch, plants are required to submit their marginal costs to the system operator who uses this information to clear the market.

Compared to bid-based dispatch, cost-based dispatch has an advantage of reducing the risk of system-wide and local market power, particularly in markets with insufficient transmission capacity (Wolak, 2003). This setting makes our modeling and analysis tractable because market power is less likely to be a large issue than bid-based markets.[8]

3.3 Data and Summary Statistics

A key advantage of studying the Chilean electricity market is that nearly all of the data relevant to market transactions are available. Although many countries including the United States make part of their electricity market data available, Chile is one of the very few countries in which nearly all micro data, including plant-level generation, cost, market dispatch mechanisms, and market clearing prices are available.[9] We use several data sets for our empirical analysis.

Hourly marginal cost at the unit level: As described in the previous section, generators in the Chilean electricity market submit their marginal cost information every day to the system operator. This cost can be different between three time segments of the day: block 1 (midnight to 8 am), block 2 (8 am to 6 pm), and block 3 (6 pm to midnight). Often, a power plant has multiple units. The data include marginal cost information at the unit level. We use this data from SING, SIC, and SEN for 2003 through 2019.

Hourly demand at the node level: Our data cover 2003 through 2020.

Hourly market clearing prices at the node level: The system operator uses marginal costs, demand, and transmission constraints to clear the market. The hourly market clearing prices are available at the node level. We collect this data from SING, SIC, and SEN for 2008 through 2019.

[8] Cost-based dispatch may not fully eliminate the exercises of market power if large firms could manipulate their reported costs or plant maintenance schedules. Based on our analysis on the reported costs and availability of power plants, we do not find evidence of large firms exercising market power in our sample period.

[9] Another country that makes much of the electricity market data publicly available is Spain (Reguant, 2014; Fabra and Reguant, 2014; Ito and Reguant, 2016).

Hourly electricity generation at the unit level. With the spot market outcomes, the system operator dispatches generation. We use hourly electricity generation at the unit level from 2014 to 2019.

Plant characteristics and investment. This data include plant-level capacity, year built, and investment.

The summary statistics in Table 1 show key characteristics of the Chilean electricity market. First, approximately 25% of electricity generation comes from SING (the northern system) and 75% comes from SIC (the southern system). This generation share is consistent with the capacity share shown in Figure 2. Second, hourly system demand does not vary much across hours as it is suggested by the hourly generation at noon and midnight in the table. This implies that electricity demand in Chile does not have much of peak and off-peak hours, as it is the case in many other electricity markets, including California, DC, Japan, and Spain-Portugal (Borenstein et al., 2002; Wolak, 2011; Ito and Reguant, 2016; Ito et al., 2018). Third, before the introduction of the interconnection, the average node price was higher in SIC than SING at noon, whereas it was higher in SING than SIC at midnight. The post-interconnection average node prices suggest price convergence both at noon and midnight between the SIC and SING regions, which we empirically investigate more in the next section.

[Table 1 about here]

4 Static Impacts of Market Integration

We first present a reduced-form event study quantification of the impacts of transmission expansion in Chile. Given the availability of detailed hourly price and cost data, we can compute the change in these variables around two events: the interconnection of SING and SIC, and the expansion of transmission to transport power to the capital.

4.1 Impacts of Market Integration on Wholesale Electricity Prices

In Figure 3, we investigate how market integration changed the price difference between SING (north) and SIC (south). For each week, we calculate the weekly average of hourly node prices in SING and SIC respectively, take the difference (SING price minus SIC price), and make time-series figures.

[Figure 3 about here]

Panel A shows the result for the boarder regions—regions within 800 km from the SING-SIC border). Before the interconnection in November 2017, there was large volatility in the price difference. For example, in 2014, the average node price was lower in SING by around $150/MWh. In contrast, it is higher in SING by around $100/MWh in 2016. Because SING and SIC were fully separated markets at this time, differences in demand or supply in each region could make the price difference between the two markets.

After the interconnection in 2017, the average price difference between SING and SIC diminished to nearly zero in the border regions. This price convergence is consistent with the prediction from the *law of one price*. Electricity is a homogeneous good, and the spot market generates one market clearing price in a market when there is no transmission congestion within the market.

The implications of transmission congestion can be seen in Panel B, where we plot the same figure by including all regions in SING and SIC. The figures suggest that the interconnection in 2017 reduced the average price difference between SING and SIC. However, the complete price convergence for the entire regions did not happen until the reinforcement in 2019. This result suggests that even after the opening of the interconnection, there was transmission congestion between the northern SIC and the southern SIC.

In Figure 4, we examine the spatial heterogeneity in price convergence. We calculate the province-level average node prices and make heat maps for the three time periods: 1) before the interconnection, 2) after the interconnection but before the reinforcement, and 3) after the reinforcement. The heat maps show the average node prices at noon, which tends to be one of the most congested hours in the transmission network in Chile because of solar generation.

[Figure 4 about here]

Prior to the interconnection, there was a steep price difference between SING and SIC at the border. The northern SIC (i.e., around Atacama desert region) had node prices near zero because zero-marginal-cost solar generation in this region depressed the market price toward zero. The heat map suggests that this inexpensive electricity could reach neither SING, due to lack of interconnection, nor the central part of SIC (i.e., around Santiago region), due to transmission constraint.

The middle heat map shows the period after interconnection but before reinforcement. The interconnection made it possible for the low-cost solar power to be transmitted to SING and to some of the central part of SIC, which lowered the node prices in these areas. In exchange, this increased the node prices in the Atacama region. However, in the southern part of SIC, prices remained high, suggesting that the transmission capacity from the northern SIC to the southern SIC was not sufficient during this period to achieve further price convergence. The map on the right presents the period after the reinforcement. It suggests that the low-cost solar power is being transmitted further to the south, making the prices more homogeneous and lower at the national level, except for the south end of SIC where some patches of relatively higher price regions remain due to the local-level transmission congestion.

4.2 Impacts of Market Integration on Generation Costs

Economic theory predicts new transmission lines could bring a textbook example of gains from trade. In autarky, the system operator in each region dispatches power plants to minimize generation cost in each region. In contrast, when a new transmission line allows two markets to trade, the system operator can dispatch to minimize total generation cost in the two regions. Thus, we predict that the interconnection and reinforcement made lower-cost power plants produce more and higher-cost plants produce less.

In Figure 5, we examine the impact of market integration on electricity generation by fuel type. After the interconnection, thermal generation in SING decreased, while solar power in SING and SIC increased. This is because the interconnection was able to relax transmission congestion for solar power near the border of SING and SIC. As a result, zero-marginal cost solar power could flow into SING, which replaced relatively more expensive coal generation.

[Figure 5 about here]

We observed that coal generation within SING came back to the pre-interconnection level after the reinforcement. This is likely because the reinforcement made it possible to transmit low-cost solar power from the Atacama region to southern SIC regions (near Santiago), which allowed SING coal plants to increase generation.

These preliminary findings indicate that the new transmission lines enabled power to be dispatched more efficiently. One way to measure this efficiency gain is to see the change in average generation cost over time before and after the new transmission investment. However, the change in average cost may not accurately measure the efficiency gain if other changes over time (e.g., changes in input costs) are not properly controlled for.

To address this empirical challenge, we estimate the impacts of market integration on the generation cost by including month fixed effects to control for seasonality and the prices of coal and natural gas to control for changes in input costs. We use c_t to denote the observed system-level generation cost at time t, and $c_t - c_t^*$ to denote the out-of-merit cost. We estimate this equation by the OLS:

$$c_t = \alpha_1 I_t + \alpha_2 R_t + \alpha_3 X_t + \theta_m + u_t, \tag{1}$$

where I_t equals one after the interconnection on November 2017, R_t equals one after the reinforcement on June 2019, X_t is a vector of control variables, θ_m is the month effects, and u_t is the error term.

Table 2 shows results for equation (1). Column 4 implies that the interconnection and reinforcement reduced the generation cost in hour 12 (a solar intensive hour) by 3.38 USD/MWh and by 2.84 USD/MWh, which are a 9.4% and 7.9% reductions relative to the mean of the dependent variable. Similarly, column 8 suggests that the interconnection and reinforcement reduced the generation cost in all hours on average by 1.33 USD/MWh and by 2.86 USD/MWh, which are a 3.4% and 7.4% reductions relative to the mean of the dependent variable.

[Table 2 about here]

A important limitation of this analysis is that it produces the static impact of market integration and does not incorporate potential dynamic effects. For example, if the entries of solar plants occurred before the market integration in the form of anticipation, such entry impacts cannot be captured by this analysis, and therefore, the current analysis is likely to attenuate the impacts of the interconnection and reinforcement. In Section 5.3, we explore how the results in Table 2 would change once we incorporate this dynamic impact using our structural model.

4.3 Impacts of Market Integration on Renewable Expansion

As we described in Section 2, the static and dynamic impacts of market integration can differ if market integration incentivizes new power plant entries. Our analyses in sections 4.1 and 4.2 showed the static impacts of market integration, but they do not incorporate the potential impact on new entries of power plants.

To investigate the importance of this point in our empirical context, we examine the entries of solar plants in Figure 6. The red-connected line shows the cumulative installed capacity for solar plants in the northern SIC region. The green solid line shows the average node price at noon, and the green dashed line shows the average node price at midnight.

[Figure 6 about here]

Before 2014, there were no solar plants in this region, and the node prices were not different between noon and midnight. When solar plants entered this region in 2014, the node prices at noon started to decline. When the total solar capacity reached around 500 MW in 2015, the node price at noon reached near zero. This is because zero-marginal cost solar generation depressed spot market prices to zero in the local market, and that low-cost electricity could not move to other regions because of transmission constraint.

This transmission constraint was relaxed when the interconnection was opened in 2017. The figure shows that the interconnection made the price at noon get back to positive levels and shrunk the difference in prices between noon and midnight. Furthermore, the reinforcement further narrowed this price difference.

The evolution of capacity investment in solar generation indicates that investors were likely to make the investment decision with the anticipation for the interconnection. Between mid-2015 and mid-2017, the node price had been near zero for solar generation. However, the investment on new solar capacity had a steady increase in this period. This investment decision does not make sense Without the anticipation that the new interconnection was going to alleviate transmission congestion and increase local node prices.

These findings from Figure 3 suggest that incorporating the dynamic impacts of market integration (i.e., the impacts on new power plant entries) can be important part of the value of the transmission expansion. In addition, this suggests that event-study style estimation in this section may not be able to properly capture this dynamic impact. In the next section, we describe how we address this question by developing a structural model of power plant entries and market integration.

5 Dynamic Impacts of Market Integration

To analyze this long-run effect, we build a structural model of power plant entries. In the model, investors consider investment for a new power plant based on the expected value of long-run profit from the investment. The net present value of investment depends on profit from subsequent years. A key element to the future expected profit is transmission constraints from its local region to other regions.

We build a simple transmission network model for the Chilean electricity market to model the spot market with transmission constraints. The attractiveness of the Chilean market is that its simple geography makes the network model tractable and makes it feasible to conduct counterfactual analysis. We simulate a few counterfactual policies on transmission capacity expansion to examine each policy's impact on capacity investment on renewables, node prices, profits, and consumer surplus.

In counterfactual analysis, we simulate what would have happened if the interconnection was not built between SING and SIC in 2017. We simulate both a static version of this counterfactual, in which solar investment remains at the observed levels, and a dynamic version of this counterfactual that endogenizes the reduction in solar investment in the absence of a grid expansion. This allows us to quantify the static and dynamic benefits of the grid expansion.

5.1 Model for Counterfactual Simulations

The model is solved in two stages. First, a short-run model is used to clear the market every day. Second, a long-run model is used to solve for the equilibrium entry of solar plants.

Short run operations The first part is the system operator's cost minimization problem under the transmission network constraints. We solve it for every day separately.[10] Given available power plant capacity, demand, and transmission network constraints, the system operator minimizes generation costs. As a result of the optimization, the production decisions of each plant and local market prices will be determined.

Mathematically, we solve the constrained optimization problem,

$$\underset{q_{it}\geq 0}{\text{Min}} \quad C_t = \sum_z \sum_{i\in I_z} c_{it} q_{it},$$
$$\text{s.t.} \quad \sum_{i\in I_z} q_{it} + imp_{zt} + exp_{zt} \geq D_{zt}, \quad q_{it} \leq k_i, \quad f_{lt} \leq F_l. \tag{2}$$

C_t is the total system-wise generation cost at time $t \in T$, c_{it} is the marginal cost of generation for plant $i \in I$ at time t, q_{it} is the dispatched quantify, imp_{zt} are imports into zone z, exp_{zt} are exports out of zone z, D_{zt} is the total demand in

[10] In practice, the Chilean operator takes into account weekly and seasonal dynamics using a longer horizon. We abstract away from these dynamics and instead include hydro power constraints to reflect water use over the seasons.

zone z, and k_i is the plant's capacity of generation. The model will have $l = 1, ..., L$ inter-regional transmission lines with net flow transmission capacity F_l. The full set of equations characterizing imp_{zt}, exp_{zt}, and f_{lt} as a function of the vector of quantities q_{it} are presented in Appendix B.

This market operator's problem is the cost minimization problem with three constraints: (1) the sum of dispatched quantities plus any imports or exports needs to be larger than or equal to the aggregate demand in each zone, (2) each plant's dispatched quantify has to be less than or equal to its generation capacity, and (3) the net flow in each inter-regional transmission line (f_l) needs to be less than or equal to its transmission capacity. This market clearing process will produce dispatch quantity for each plant and market clearing prices at each node (p_{it}), which is defined by the shadow value on the demand constraint of each zone z.

In addition to these fundamental constraints, we incorporate operational constraints that are tailored to better describe the Chilean context, including minimum and maximum hydro power constraints for each zone, minimum production requirements for a baseload plant that is always operating during our sample period, and hydro power as must-run in cluster 2.[11]

While the short-run model is a stylized representation of the Chilean electricity market that abstracts away from many aspects of electricity market operations, Figure 7 shows that it can do a good job at capturing the evolution of prices in the data.

[Figure 7 about here]

Long run investment The second part of the model is an investor's decision regarding investment in new renewable plants. With this market clearing process in equation (2) in mind, renewable investors will expand investment in new renewable plants until the following zero-profit condition is satisfied:

$$E\left[\sum_{t\in T}\left(\frac{p_{it}q_{it}}{(1+r)^t}\right)\right] = \rho k_i. \tag{3}$$

Π_i is the expected profit from the investment, r is the discount rate, p_{it} is the market clearing price from the solution of equation (2), and ρ is the investment cost per generation capacity. Due to the direct cannibalization effect of solar power on market prices, the right hand side of the equation is a declining function of capacity k_i. In principle, we would need to solve for investment specific to each area z. However, given the geography of Chile, we focus on solving for optimal investment in cluster 2, which is the one with most relevant utility-scale solar investment and a higher presence of zero prices in the absence of transmission expansion.

To solve the investment problem, we compute the outcomes of the short-run model under alternative network configurations and levels of solar investment. We then search for the level of investment that satisfies the zero profit

[11] Water plays a minor in cluster 2, with small produced quantities that are observed even under zero prices, something hard to replicate with our model.

condition.

5.2 Counterfactual Simulation Results

We use this structural model to compute three main scenarios during the period after the interconnection. First, we solve for the equilibrium under the observed expanded grid and solar investment, and we call it by *Actual scenario*. Second, we compute a counterfactual policy simulation by simulating what would have happened if the interconnection and reinforcement lines had not been built between SING and SIC in 2017. This can be done by changing the values of F_l in the model, and we call this scenario by *No market integration*. The third scenario is equivalent to the second scenario, but we incorporate the dynamic impact on power plant entries—some entries would not happen in the absence of market integration because such investment would become unprofitable. We call this it by *No market integration (dynamic)*. The node prices at noon in the northern SIC region (Atacama region) before the interconnection suggest that most of the solar capacity investment did not make sense in the absence of the interconnection because firms would not have gained profit from wholesale prices near zero (Figure 6).

To compute the dynamic scenario, we use our structural model to compute the amount of solar capacity investment that would not have happened in the absence of market integration. As we reduce the entries of solar plants in the model, the node price in Atacama region (solar-intensive region) increases from zero to positive levels. We compute how much solar plant entries have to be excluded to make the solar investment profitable in the absence of market integration. We have data on the cost of solar plant investment and use the Chilean government's official discount rate for public infrastructure investments, which is 6% in Sistema Nacional de Inversiones (2011). We show the result in Appendix table A.1. In the absence of market integration, 70% of the solar plant capacity investment could not have occurred based on the assumption that investors need to have the net present value of their investments become positive in 20 years. Thus, our third scenario is the market equilibrium with no market integration and a 70% reduction of the solar plant capacity relative to the static equilibrium level.

These counterfactuals allow us to compute both the static and dynamic impacts of the transmission line, so that we can decompose the overall impact of the line between static and dynamic effects. This analysis provides insight on the potential biases of using the static model alone.

In Figure 8, we show the equilibrium prices at noon in Atacama region for the three scenarios. The actual scenario shows the same pattern as it is observed in the data in Figure 6. The price was often zero before the interconnection in 2017 because some of solar production could not be exported to other regions. After the interconnection, the price in actual scenario increased to around 50 USD/MWh as this region was able to export solar power to other regions. In contrast, the price would not increase much in the absence of market integration because of the inability of exporting solar power. This is certainly not a realistic equiribrium in a dynamic sense because solar power would be unprofitable investment. With the dynamic consideration (i.e. 70% less solar capacity), the price in this region can be high enough to keep the solar investment profitable.

[Figure 8 about here]

Figure 9 presents solar generation (GWh/day) for the three scenarios. The different between the static counterfactual and the actual scenario shows how much solar power cannot be produced without market integration because of inability of exporting solar power. The solar generation in the dynamic scenario suggests that ignoring the dynamic impact would understate the impact of market integration on renewable expansion.

[Figure 9 about here]

Similarly, Figure 10 indicates that generation costs are highest in the absence of solar investment and market integration, which implies that ignoring the dynamic impact understates the benefits of market integration. This is consistent with a theoretical prediction (Observation 1) in Section 2.

[Figure 10 about here]

In Table 3, we provide a summarized comparison between these three sets of counterfactuals and test some of the theoretical predictions described in Section 2. Without the market integration, solar generation would be less than the actual scenario by 17.03% in the static case and 45.48% if we incorporate the dynamic impact on solar plant entries. In line with Observation 1, in the presence of anticipated solar investments, the static approach understates the reduction in generation costs. The static approach predicts a reduction in generation costs of 4.98% (10.13% at noon, an hour with high solar generation). However, the dynamic gross benefits are 6.36% (13.64% at noon). The results from that observation also suggest that 4.98% is an upper bound on the *net* benefits of investment (accounting for solar investment costs).

[Table 3 about here]

The system-level price results suggest that the market integration increases the system-level price if we ignore the dynamic impact but decreases it if we incorporate the dynamic impact. This is consistent with Observation 2 in Section 2. Furthermore, the results on the prices in Atacama (a solar-intensive region in the north) and Santiago (a demand center in the central-south) are consistent with Observation 3. If we do not incorporate the dynamic effect, the price in Atacama would be predicted to be very low in the absence of market integration (1.95 USD/MWh in column 2). This is because the static approach ignores the fact that some solar entries would be unprofitable without market integration. As a result, the impacts of market integration on price convergence between these two regions are overstated in the static result in column 2 compared to the dynamic result in column 3, as suggested by Observation 3.[12]

[12]Note that Observation 3 is derived under the assumption that there is full price convergence. As shown by the column under the actual scenario, convergence is not complete.

5.3 Regression comparison and dynamic bias

In Table 4, we present a comparison of the regression estimates from the effect of the line when investment happens at the time of expansion. Panel A presents an analogous regression to Table 2 but using our simulated data, as opposed to the original data. We confirm that the model outputs are consistent with the observed data. For specification (4), we find that the impacts of the line are the same whether we use the actual data vs. the one generated by the model.

[Table 4 about here]

We run the same regressions but under the following thought experiment. What would happen to our regression estimates if investment were coincidental to the line expansion, as opposed to anticipated? To perform this exercise, we create a time series of average costs that has reduced solar investment before the interconnection, it goes to partial investment at the point that the interconnection occurs, and only achieves investment as observed after the reinforcement happens. We show the results of this thought-experiment in in Panel B of Table 4.

In line with the theoretical predictions in Section 2, we observe that the anticipated investment in solar panels leads to an understatement of the benefits of the line. Accounting for the dynamic benefits of the lines increases the estimates of cost reductions by 15-45% depending on the hour of the day and the expansion considered. This highlights some of the added benefits that might be underestimated by a more naïve event-study design.

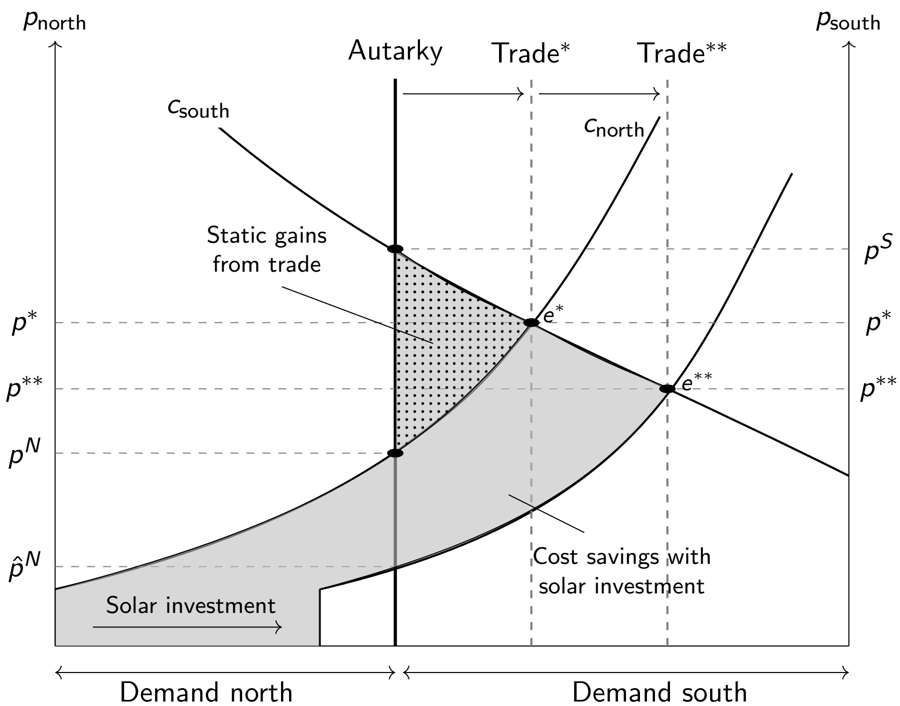
6 Conclusions

In this paper, we begin with a simple theoretical model that highlights why market integration plays a key role in renewable expansion in static and dynamic ways. Statically, market integration improves allocative efficiency by gains from trade. Dynamically, it incentives new entries of renewables plants. To quantify these theoretical predictions, we build a structural model of power plant entries and apply it to a recent increase in market integration in the Chilean electricity market—two fully separated markets were integrated into one market in 2017.

We find that market integration resulted in price convergence across regions, increases in renewable generation, and decreases in overall generation cost due to gains from trade. Furthermore, our counterfactual simulations quantify that a substantial amount of renewable entry would not have occurred in the absence of market integration. We show that ignoring this dynamic effect would significantly understate the benefits of market integration, including its impacts on allocative efficiency and renewable expansion.

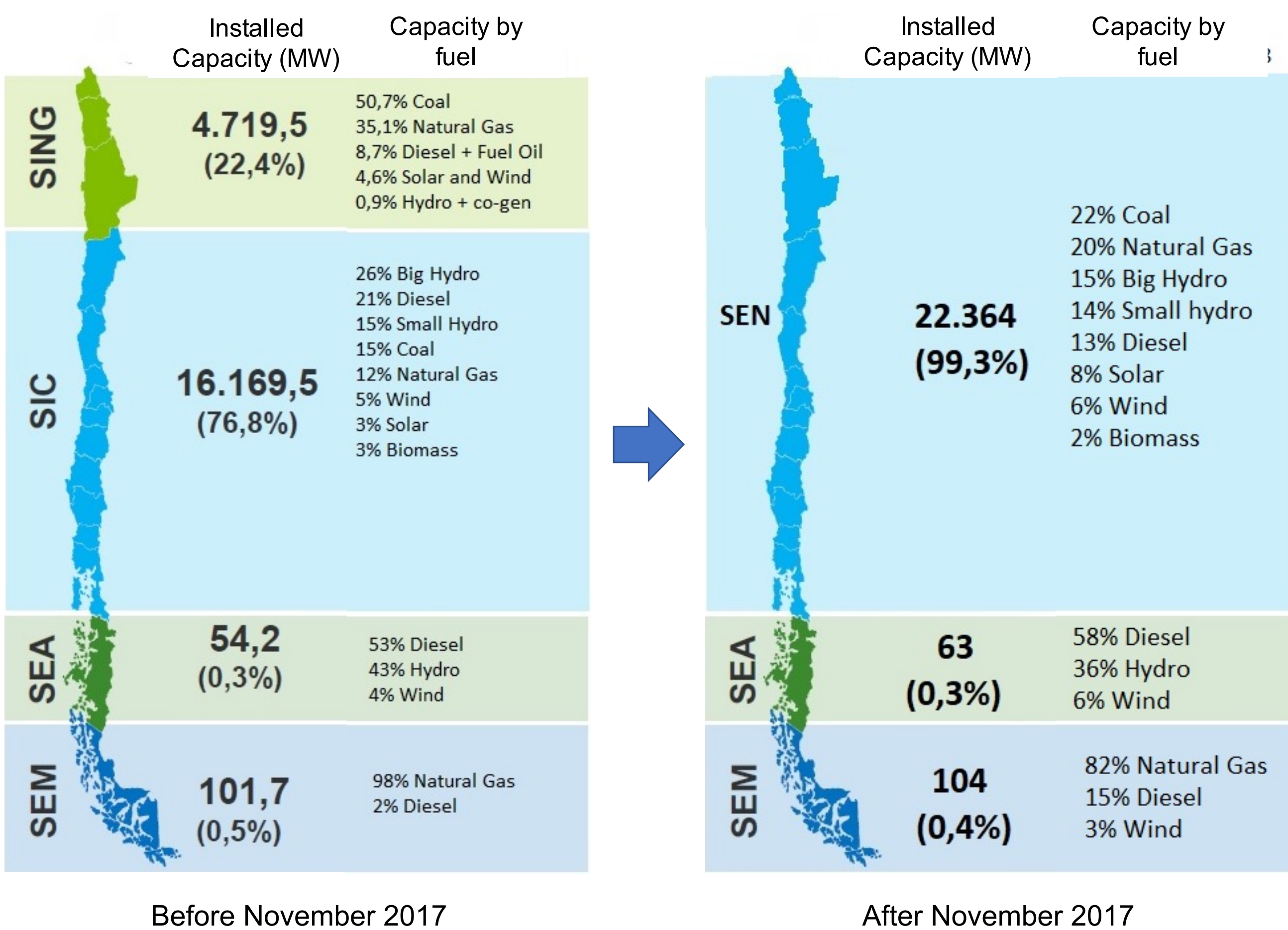
Figures

Figure 1: Static and Dynamic Impacts of Market Integration



Note: This figure summarizes theoretical predictions described in Section 2. The static case considers the impact of market integration, assuming that it does not affect new entries of solar plants, whereas the dynamic case takes into account for the impact on solar investment. In the static case, the market integration moves the equilibrium to e^*, resulting in the static gains from trade. In the dynamic case, the market integration also induces new entries of solar plants, which have zero marginal cost. As a result, it shifts the cost curve in the North to the right. This equilibrium (e^{**}) generates an additional cost savings from the impact of market integration on the new entries of solar plants.

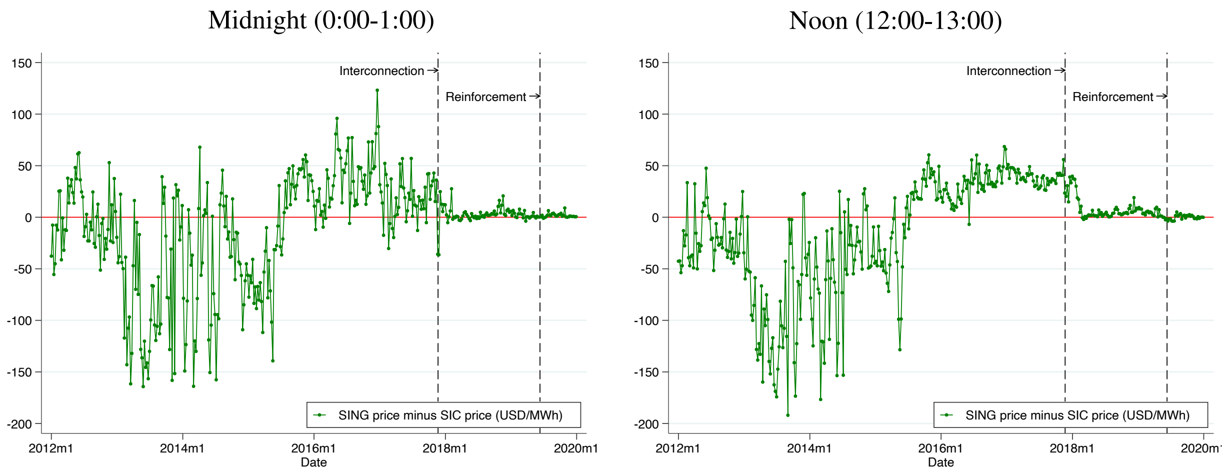
Figure 2: Market Integration in the Chilean Electricity Markets



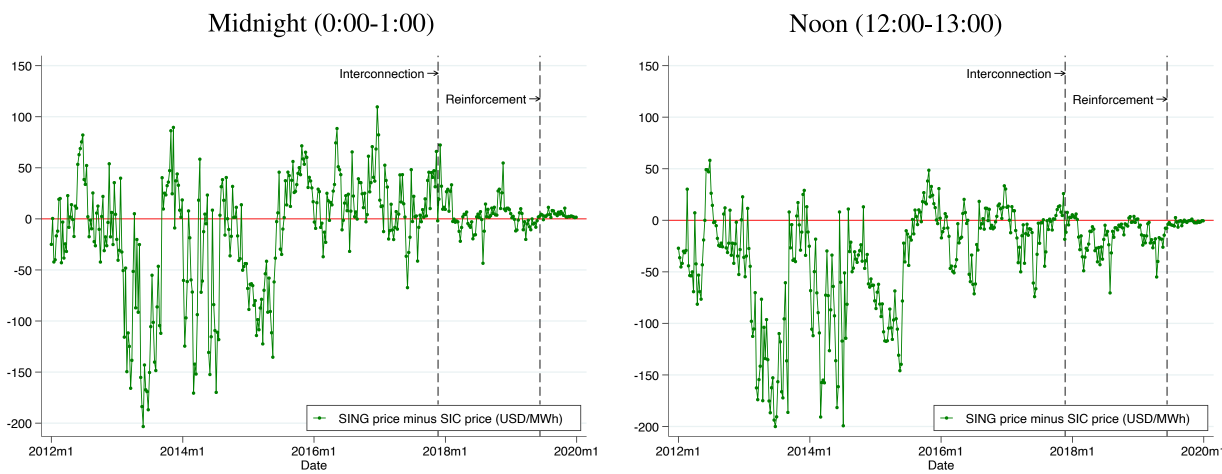
Note: The two largest electricity markets in Chile (SING and SIC) were integrated to become one market (SEN) in November 2017.

Figure 3: Impacts of Market Integration on the Price Difference Between SING (North) and SIC (South)

Panel A: Border regions (within 800 km from the SING-SIC border)

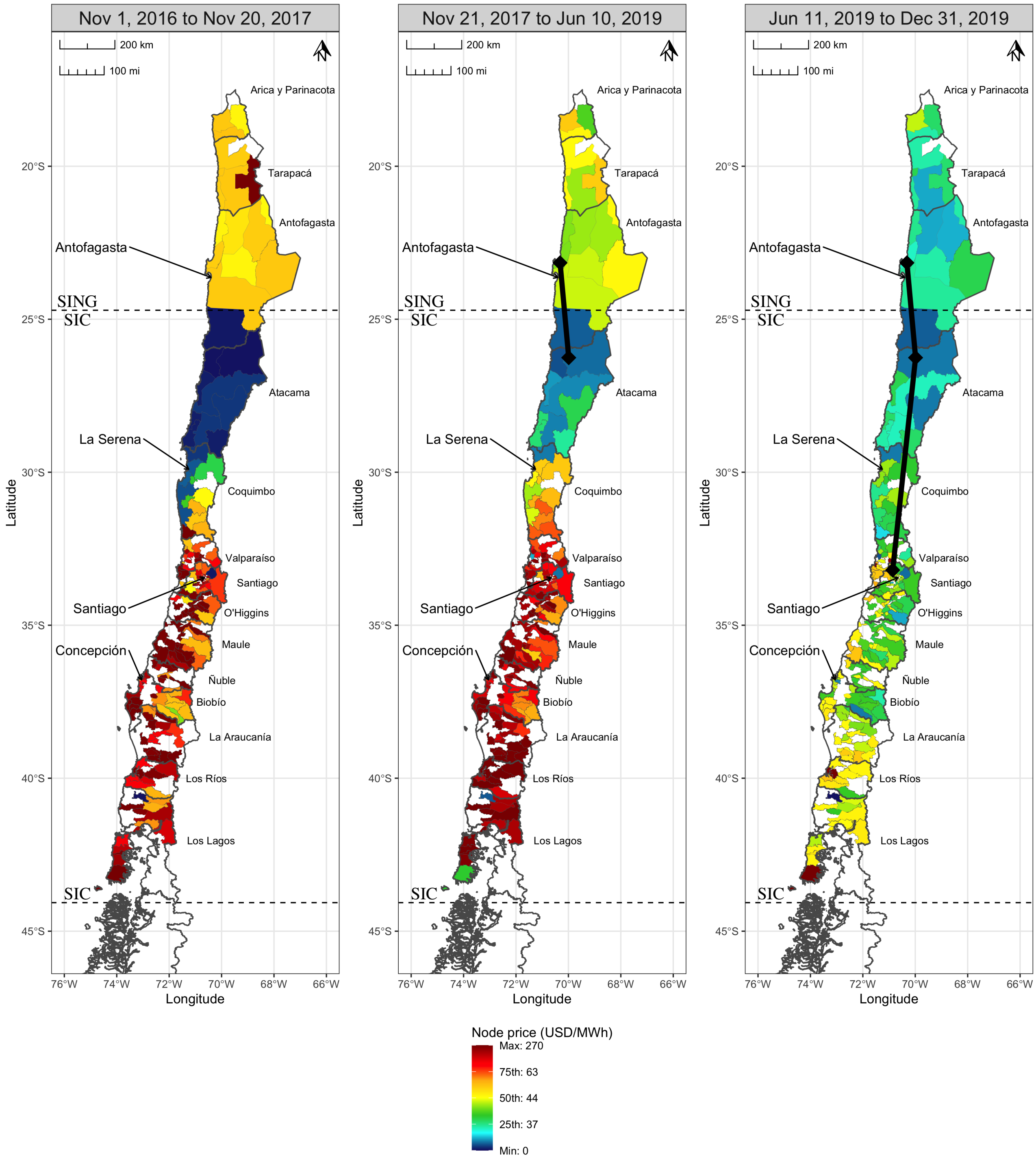


Panel B: All regions



Note: This figure examines the impacts of market integration on the difference in wholesale electricity prices between SING and SIC. Each dot is the difference between the weekly average of hourly node prices in SING and the weekly average of hourly node prices in SIC (i.e, SING minus SIC), weighted by electricity generation in each node.

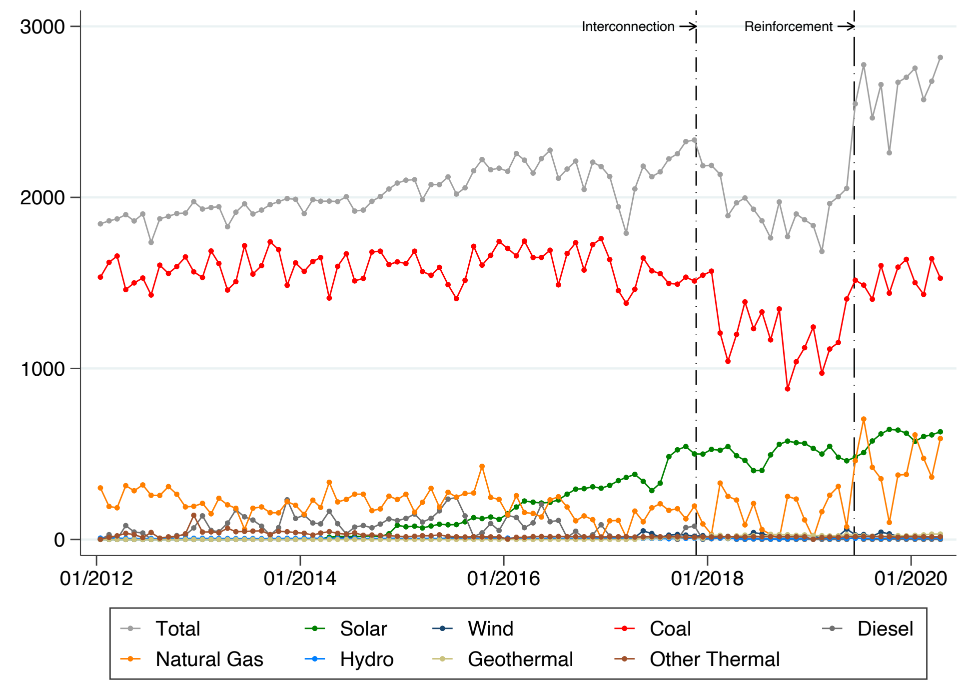
Figure 4: Impacts of Market Integration on Spatial Variation in Electricity Prices



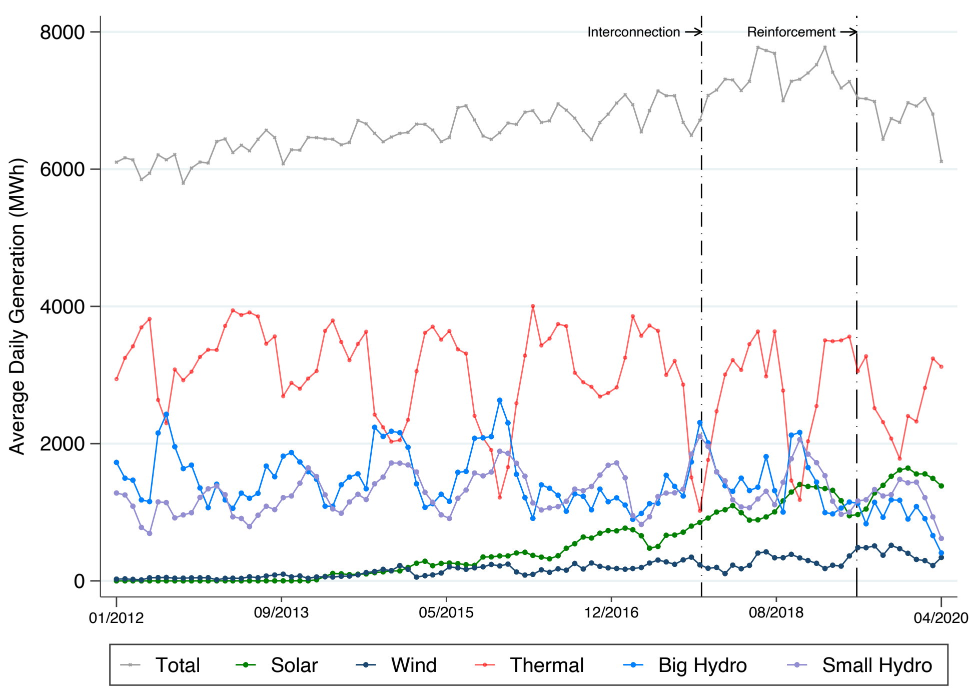
Note: These heat maps examine spatial heterogeneity in wholesale electricity prices. We calculate the province-level average node prices and make heat maps for the three time periods: 1) before the interconnection, 2) after the interconnection but before the reinforcement, and 3) after the reinforcement. We use the percentiles of the node price distribution to define color categories as shown in the legend. The maps also include names of regions, major cities, and the locations of the interconnection and reinforcement transmission lines.

Figure 5: Impacts of Market Integration on Electricity Generation by Fuel Type

Panel A: SING (north)

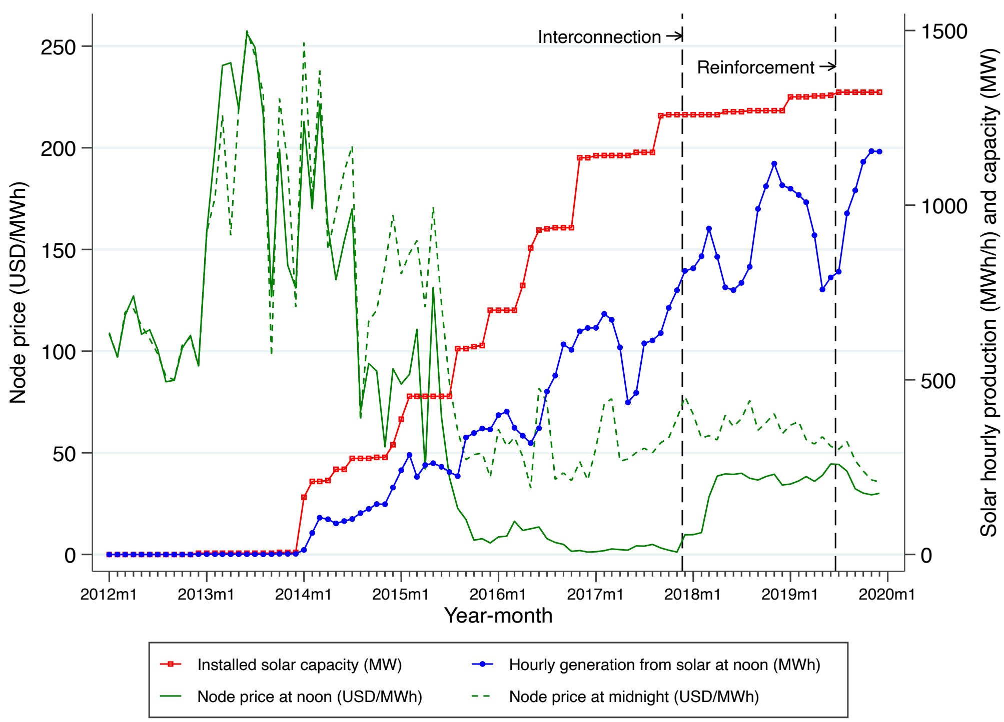


Panel B: SIC (south)



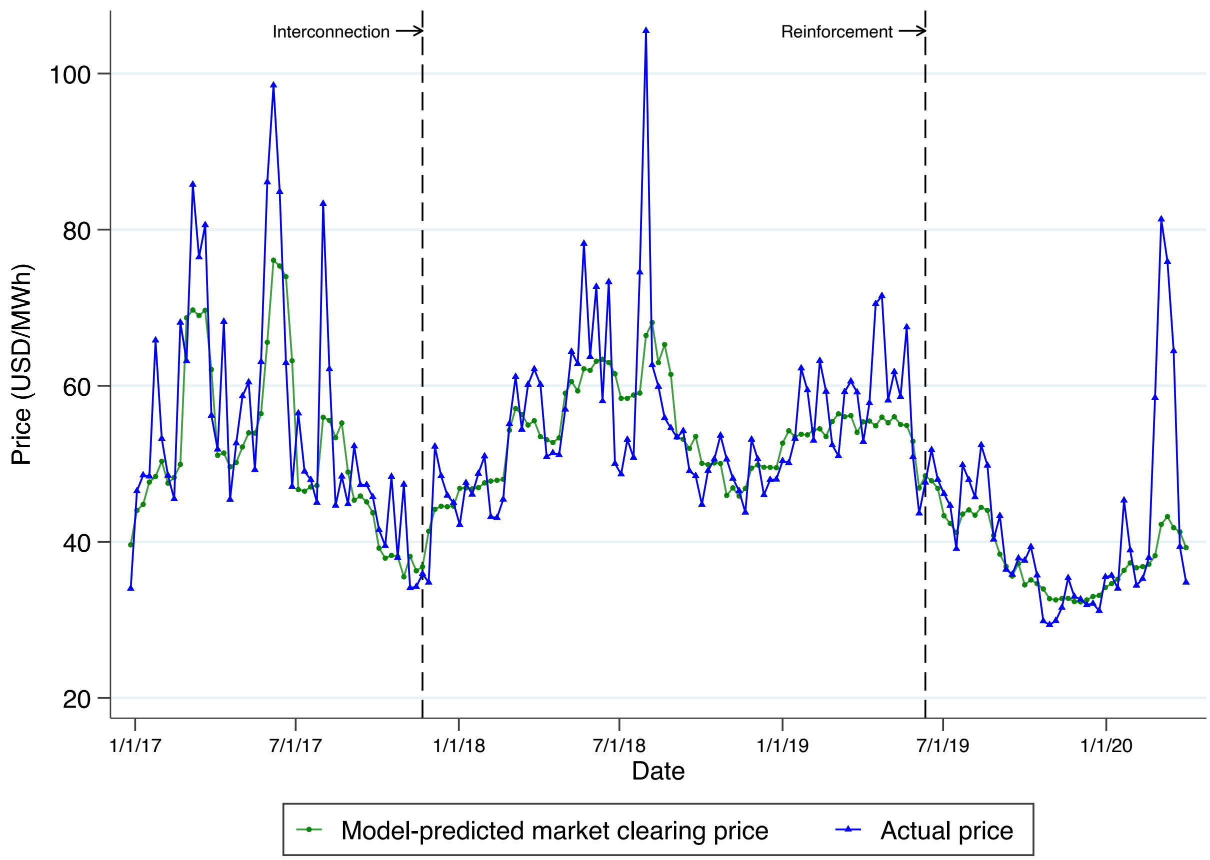
Note: This figure shows the average daily generation (MWh) by fuel type over the calendar months.

Figure 6: Impacts of Market Integration on Renewable Expansion



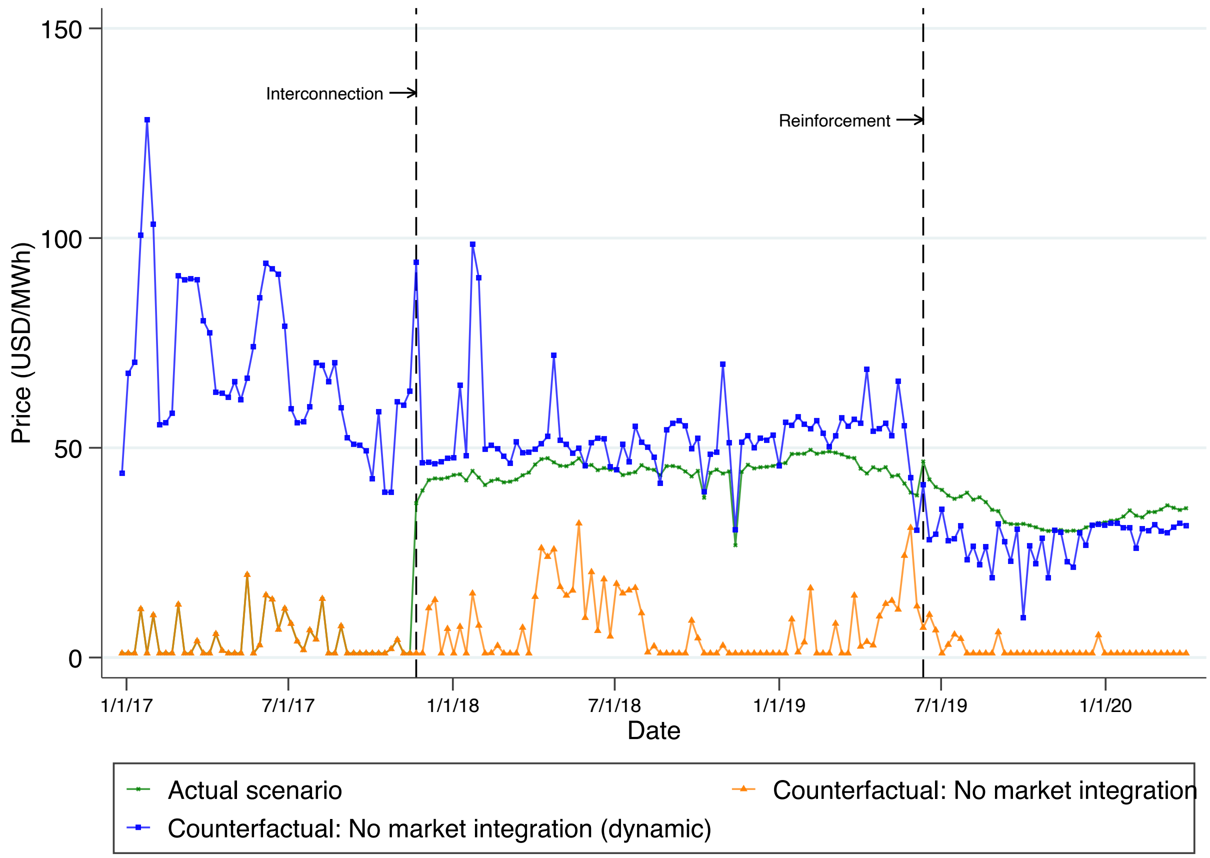
Note: This figure shows the cumulative installed capacity of solar plants, average hourly generation for each month, and node prices for these plants at noon and midnight.

Figure 7: Model Fit: Model-Predicted Market Price and Actual Market Price in the Data



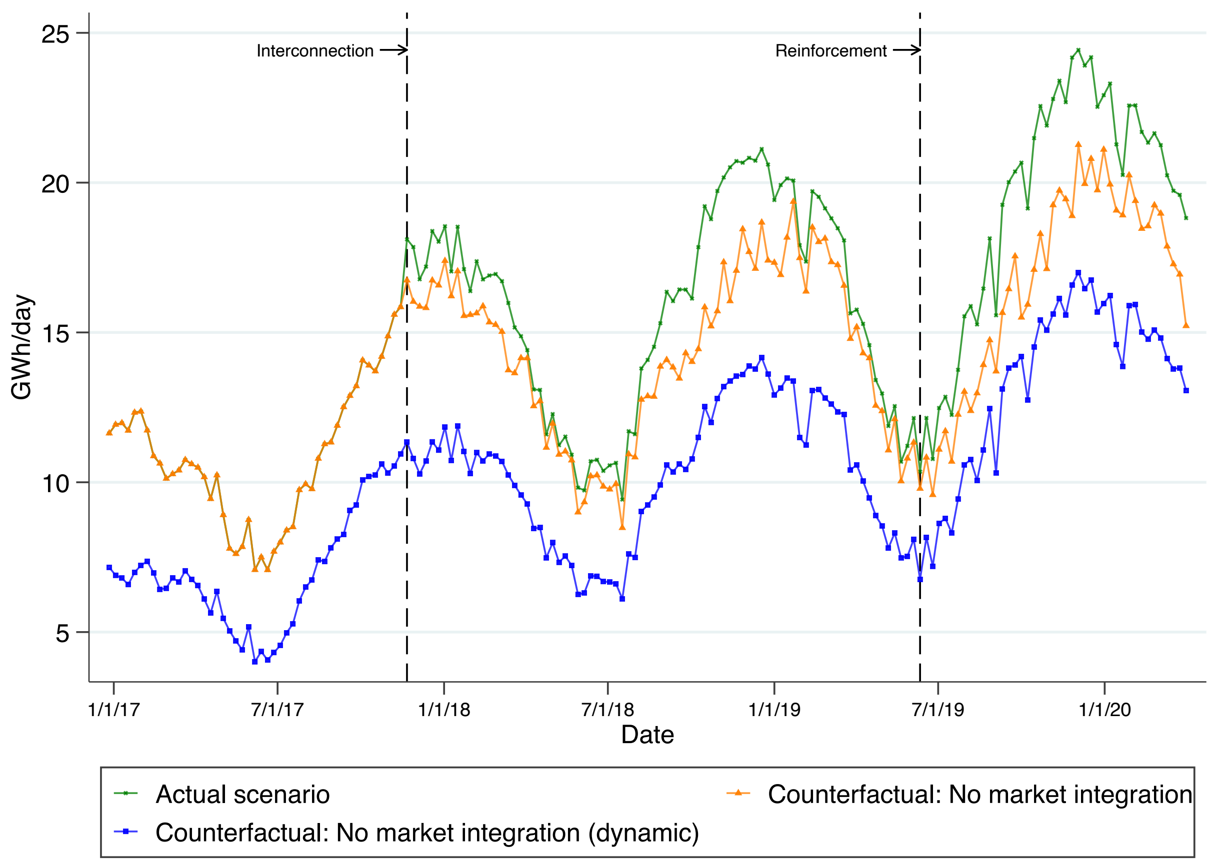
Note: This figure compares the price predicted by the structural model described in Section 5 and actual prices in the data. Each dot represents the weekly average of hourly node prices from all nodes, weighted by the generation at the node level.

Figure 8: Counterfactual Simulation Results: Prices in Atacama (Renewable-Intensive Region)



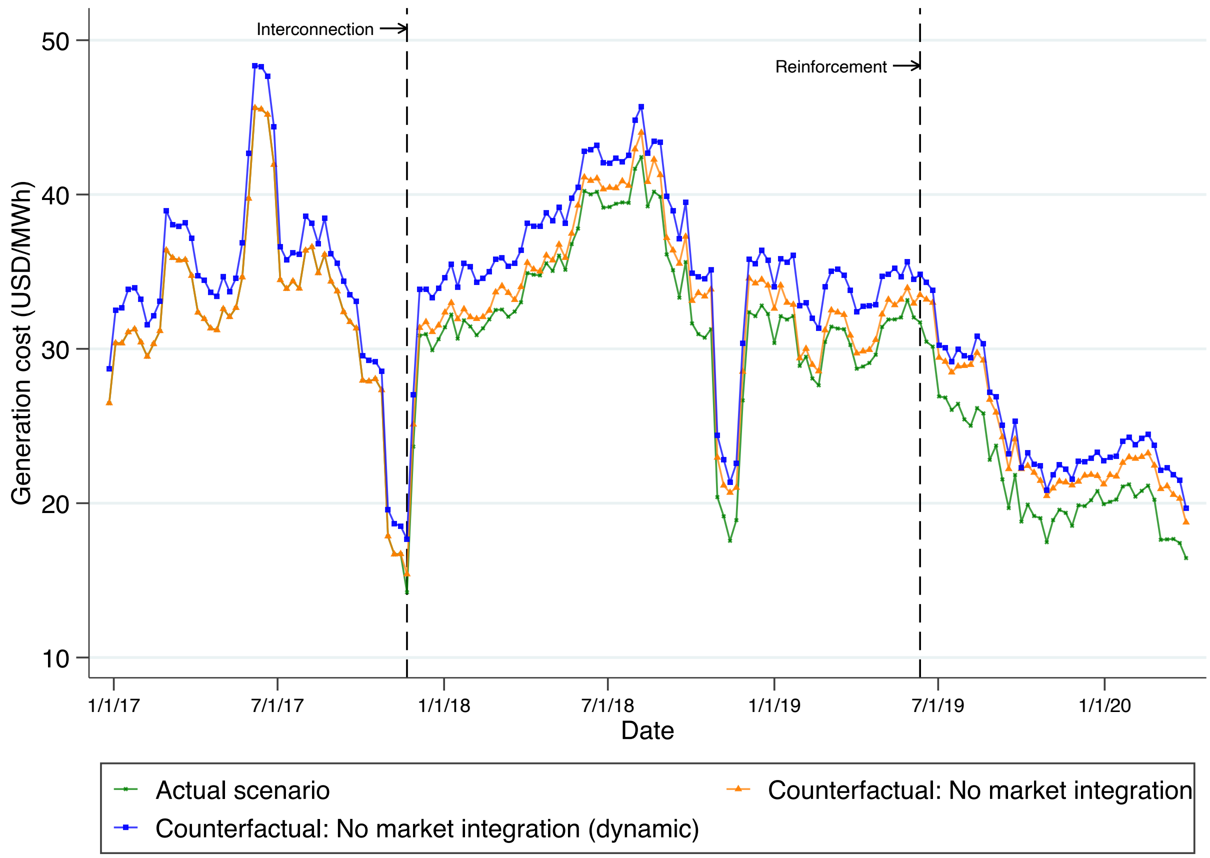
Note: We use the structural model and counterfactual simulations described in Section 5.2 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second scenario is a counterfactual case in which the market integration did not happen. The third scenario is equivalent to the second scenario, but we incorporate the dynamic impact on power plant entries—some entries would not happen in the absence of market integration because such investment would become unprofitable. This figure presents electricity generation cost (USD/MWh) for these three scenarios. Each dot represents the weekly average of generation cost per MWh in USD.

Figure 9: Counterfactual Simulation Results: Solar Generation



Note: We use the structural model and counterfactual simulations described in Section 5.2 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second scenario is a counterfactual case in which the market integration did not happen. The third scenario is equivalent to the second scenario, but we incorporate the dynamic impact on power plant entries—some entries would not happen in the absence of market integration because such investment would become unprofitable. This figure presents total electricity generation from solar plants (GWh/day) for these three scenarios. Each dot represents the weekly average of solar generation per day in GWh.

Figure 10: Counterfactual Simulation Results: Electricity Generation Cost (USD/MWh)



Note: We use the structural model and counterfactual simulations described in Section 5.2 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second scenario is a counterfactual case in which the market integration did not happen. The third scenario is equivalent to the second scenario, but we incorporate the dynamic impact on power plant entries—some entries would not happen in the absence of market integration because such investment would become unprofitable. This figure presents electricity generation cost (USD/MWh) for these three scenarios. Each dot represents the weekly average of generation cost per MWh in USD.

Tables

Table 1: Summary Statistics

	Pre-Interconnection (Nov. 2016 - Nov. 2017)		Post-Interconnection (Nov. 2017 - Dec. 2019)
	SIC	SING	SEN
Hourly total generation at noon (MWh)	6843	2143	9341
	(680)	(188)	(685)
Hourly total generation at midnight (MWh)	6284	2260	8879
	(349)	(198)	(393)
Node price at noon (USD/MWh)	57.79	46.22	49.90
	(36.80)	(21.14)	(24.81)
Node price at midnight (USD/MWh)	59.38	76.49	55.33
	(29.52)	(42.40)	(24.04)
Variable cost: Thermal (USD/MWh)	44.87	43.93	46.21
	(16.16)	(14.85)	(17.62)
Installed capacity (MW):			
Thermal	8168	4227	12775
Hydro	6649	16	6734
Solar	1384	654	2642
Wind	1204	201	2115

Note: This table shows the summary statistics of our data.

Table 2: Static Impacts of Market Integration on Generation Cost (USD/MWh)

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-0.15	-2.85	-2.82	-3.38	1.55	-0.98	-0.94	-1.33
	(0.45)	(0.39)	(0.39)	(0.36)	(0.41)	(0.32)	(0.32)	(0.31)
1(After the reinforcement)	-11.52	-3.13	-2.98	-2.86	-11.05	-3.17	-2.92	-2.86
	(0.53)	(0.73)	(0.75)	(0.68)	(0.48)	(0.60)	(0.61)	(0.60)
Coal price [USD/ton]		0.21	0.21	0.20		0.20	0.20	0.20
		(0.02)	(0.02)	(0.02)		(0.02)	(0.02)	(0.02)
Natural gas price [USD/m^3]			7.72	6.81			12.69	12.50
			(8.81)	(8.07)			(7.19)	(7.05)
Scheduled demand (GWh)				2.17				0.06
				(0.15)				(0.01)
Constant	38.38	17.96	17.13	-0.14	39.87	20.06	18.71	8.85
	(0.35)	(1.65)	(1.90)	(2.13)	(0.32)	(1.35)	(1.55)	(2.13)
Mean of dependent var	36.12	36.12	36.12	36.12	38.87	38.87	38.87	38.87
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R2	0.34	0.81	0.81	0.84	0.34	0.84	0.84	0.85

Note: The dependent variable is average generation costs for the entire system in USD/MWh.

Table 3: Counterfactual Simulation Results

	(1)	(2)	(3)	(4)	(5)
	Actual	Counterfactual		Impacts of market integration	
	Market integration	No market integration (static)	No market integration (dynamic)	% change (1) from (2)	% change (1) from (3)
Solar generation (GWh/day)	19.42	16.60	13.35	17.03%	45.48%
Generation cost (USD/MWh): hour 12	21.80	24.26	25.25	-10.13%	-13.64%
Generation cost (USD/MWh): all hours	25.21	26.53	26.92	-4.98%	-6.36%
Price at noon in all regions (USD/MWh)	36.78	37.25	39.47	-1.26%	-6.82%
Price at noon in Atacama (USD/MWh)	34.47	1.95	28.08	1665.99%	22.79%
Price at noon in Santiago (USD/MWh)	38.28	43.86	43.86	-12.73%	-12.73%
Price difference (Santiago - Atacama)	3.81	41.91	15.79	-90.92%	-75.89%

Note: This table shows the counterfactual simulation results in Section 5.2. Column (2) shows the market equilibrium before the expansion of the grid. Column (3) shows the market equilibrium before the expansion of the grid and assumes that solar investment expansion has not been realized (only 30% of solar investment is present).

Table 4: Impacts of Market Integration on Generation Cost with Dynamic Correction (USD/MWh)

Panel A: Generation Cost (USD/MWh) predicted by Model under Observed Investment

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-0.22	-2.44	-2.39	-3.09	1.91	-0.12	-0.06	-0.66
	(0.42)	(0.37)	(0.37)	(0.32)	(0.37)	(0.30)	(0.30)	(0.28)
1(After the reinforcement)	-9.66	-3.30	-3.01	-2.86	-9.23	-3.39	-3.06	-2.96
	(0.49)	(0.70)	(0.72)	(0.61)	(0.44)	(0.56)	(0.57)	(0.54)
Coal price [USD/ton]		0.18	0.18	0.17		0.17	0.17	0.16
		(0.02)	(0.02)	(0.02)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			14.70	13.55			16.67	16.38
			(8.46)	(7.18)			(6.75)	(6.38)
Scheduled demand (GWh)				2.75				0.08
				(0.14)				(0.01)
Constant	32.66	15.46	13.89	-7.96	33.55	17.56	15.78	0.75
	(0.33)	(1.59)	(1.83)	(1.89)	(0.29)	(1.27)	(1.46)	(1.93)
Mean of dep var	30.70	30.70	30.70	30.70	33.15	33.15	33.15	33.15
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R2	0.30	0.78	0.78	0.84	0.30	0.82	0.82	0.84

Panel B: Generation Cost (USD/MWh) predicted by Model under "Perfectly-Timed" Investment

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.09	-3.24	-3.17	-3.84	1.54	-0.48	-0.42	-1.01
	(0.42)	(0.38)	(0.38)	(0.33)	(0.37)	(0.30)	(0.30)	(0.29)
1(After the reinforcement)	-10.90	-4.69	-4.32	-4.17	-9.74	-3.91	-3.55	-3.45
	(0.49)	(0.71)	(0.73)	(0.63)	(0.44)	(0.56)	(0.58)	(0.55)
Coal price [USD/ton]		0.17	0.17	0.16		0.17	0.17	0.16
		(0.02)	(0.02)	(0.02)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			19.26	18.16			18.57	18.29
			(8.56)	(7.40)			(6.81)	(6.46)
Scheduled demand (GWh)				2.64				0.08
				(0.14)				(0.01)
Constant	34.78	18.35	16.29	-4.67	34.43	18.77	16.79	2.03
	(0.33)	(1.61)	(1.85)	(1.95)	(0.29)	(1.28)	(1.47)	(1.96)
Mean of dep var	31.98	31.98	31.98	31.98	33.67	33.67	33.67	33.67
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R2	0.36	0.79	0.80	0.85	0.33	0.83	0.83	0.84

Note: The dependent variable is average generation costs for the entire system in USD/MWh.

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Appendix

A Proofs

Proof Observation 1

Proof. First we need to show that gross gains from trade are largest in the full dynamic comparison.

- If investment effects are ignored, we need to show that total gross costs are larger in the absence of solar investment, which is trivially satisfied. For any positive q^{solar}, total gross costs go down. Numerically,

$$GainsTrade - GainsTrade_{noinvest} = \frac{\beta^N \beta^S}{2(\beta^N + \beta^S)} q^{solar}(2D - q^{solar}) > 0,$$

  for relevant well-defined solution, as $q^{solar} < D$.

- If investment has already realized, then the distrotion comes in the "before" period. We need to show that autarky costs are smaller with anticipated investment, which is also trivial in a general setting as, for any positive q^{solar}, total gross costs go down. Numerically,

$$GainsTrade - GainsTrade_{investearly} = \beta^N q^{solar}(D^N - \frac{q^{solar}}{2}) > 0,$$

  which is well defined for $q^{solar} \leq D^N$. If $q^{solar} > D^N$, then it is also true as the difference in gains from trade becomes simply $(\beta^N D^{N2})/2$, the costs of producing under autarky in the North.

The second part is a bit more subtle but also follows from very general economic principles, as investment in solar needs to improve outcomes if profitable.

- If investment is delayed and therefore ignored, the gains from the expansion will be lower. Numerically, we need to show that

$$\frac{\beta^N \beta^S}{\beta^N + \beta^S}(D - \frac{q^{solar}}{2}) > c,$$

  which plugging in q^{solar} gives $\frac{c}{2} + \frac{\beta^N \beta^S}{\beta^N + \beta^S}\frac{D}{2} = \frac{c}{2} + \frac{p^*}{2} > c$, which holds as $p^* > c$ by assumption.

- If investment is anticipated but investment costs are ignored, we need to show that the missed gains from trade are smaller than the costs of solar. Numerically, we need to show

$$\beta^N(D^N - \frac{q^{solar}}{2}) < c,$$

which is by construction true as the equilibrium price is equal to c and larger than $\beta^N(D^N - q^{solar})$, the price in the North under solar investment and autarky.

□

Proof Observation 2

Proof. Price reductions being understated can be shown very generally. In full equilibrium, price reductions are $\overline{p} - p^{**}$, where $\overline{p}$ is the average price under autarky.

- Under early investment, price reductions are $\hat{p} - p^{**}$, where $\hat{p}$ is the average price under autarky but with solar investment. Because $\hat{p} < \overline{p}$, it follows that the difference is understated.
- Under late investment, price reductions are $\overline{p} - p^{*}$. Because $p^{**} < p^{*}$, it follows that the difference is understated.

□

Proof Observation 3

Proof. Under the assumption that prices converge after the interconnection, then price convergence is defined by the difference in the early period. Taking advantage that we have assumed that $p^N \leq p^S$,

- If investment is anticipated, $\hat{p}^N \leq p^N$, and thus $p^S - \hat{p}^N > p^S - p^N$.
- If investment is delayed, price differences are not distorted.

If the size of the transmission line is not enough for prices to converge, the result does not change if investment is anticipated, as the "after" equilibrium prices would be the same. For the case of investment delays, because net trade is smaller in the absence of investment, then price convergence is more likely if there is no investment. Therefore, price convergence might be overstated. Mathematically, net trade with solar investment is given by $\frac{\beta^S D^S - \beta^N (D^N - q^{solar})}{\beta^N + \beta^S}$ and net trade without solar investment is given by $\frac{\beta^S D^S - \beta^N D^N}{\beta^N + \beta^S}$, confirming that unrestricted trade is largest in the solar equilibrium.

If the constraint is binding, price differences will be weakly larger with solar investment. Visually, the offer curve from the North with solar is always to the right of the offer curve without solar and, therefore, for a restricted level of trade, the price difference will always be weakly larger with solar investment. Therefore, convergence will be higher in the absence of investment and binding transmission constraints. □

B Short-run dispatch model

We present here a fully fledged characterization of the short-run model with all the constraints explicitly spelled out.

Variables We solve for the following variables:

- q_{it}: Generation of each power plant, at most equal to the plant's capacity.
- q_clust_{ct}: Thermal generation at each cluster, defined as the sum of q_{it} belonging to cluster c.
- q_solar_{ct}: Solar generation at each cluster, at most equal to available solar power that hour-day.
- q_wind_{ct}: Wind generation at each cluster, at most equal to available solar power that hour-day.
- q_hydro_{ct}: Hydro generation at each cluster, subject to seasonality constraints (min and max).
- d_{ct}: Output reaching final consumers at each cluster, equal or greater than demand, when there are constraints that require spilling power beyond renewables (e.g., due to autarky counterfactuals in which must-run production is higher than demand in a given region).
- $inflow_{zct}$: Power inflowing from line z into cluster c.
- $outflow_{zct}$: Power outflowing from line z into cluster c.

Objective function The planner minimizes the costs of production:

$$\min \sum_{c,t} \sum_{i \in c} c_{it}\, q_{it} + C_{hydro,c}(q\_hydro_{ct}) + c_{solar}\, q\_solar_{ct} + c_{wind}\, q\_wind_{ct}.$$

The costs from thermal generation come from the regulatory data and are at the plant-day level. The data for hydro costs is taken also from the data, and approximated as a piece-wise linear function given that hydro production at the cluster level is the conjunction of several inter-related plants. We include a small marginal cost to solar and wind production to break ties in the presence of oversupply of renewable production. To circumvent the need for modeling the water basins in detail, we approximate from the data the observed cost of producing water at different levels with an estimated cost function. For each cluster-year-month, we regress the generation-weighted average price of hydro plants on total hydro generation in that cluster. The coefficient and constant define the hydro supply curve observed during those month conditions.[13] We additionally include a lower and upper bound to hydro production based on the minimum and maximum observed hydro generation in that cluster-year-month.[14]

[13] We constrain the supply curve to be non-decreasing, and set the slope equal to zero whenever this constraint is binding and set the constant term to be mean(generation-weighted average price of hydro plants) in that cluster-year-month.

[14] Note that the the x-intercept of the hydro supply curve also sets an implicit lower bound on hydro production when the price is zero.

Constraints The model is very simple given Chile's geography. To define the constraints for the network, we define the following matrix, which defines the lines are connected:

$$T = \begin{bmatrix} 1 & 0 & 0 & 0 \\ 1 & 1 & 0 & 0 \\ 0 & 1 & 1 & 0 \\ 0 & 0 & 1 & 1 \\ 0 & 0 & 0 & 1. \end{bmatrix}$$

Rows represent each cluster (dim=5) and columns represent each line (dim=4). There are four lines going from North to South. Cluster 1 is only connected to cluster 2 via line 1, cluster 2 is connected to 1 (line 1) and 3 (line 2), etc. In sum, line 1 connects 1 and 2, line 2 connects 2 and 3, line 3 connects 3 and 4, and line 4 connects 4 and 5.

The flow variables reflect net flows between clusters and are defined as positive variables. For a given line z and cluster c, either the inflow is positive or the outflow is positive, but not both. Outflows from cluster c in line z appear as inflows to the cluster to which the line connects. Outflows and inflows are limited by the size of the line, L_z. The size of the line can change depending on the scenario considered.

$$\begin{aligned} & 0 \leq inflow_{zct} \leq T_{zc} L_z, && \forall z, \forall c, \forall t \\ & 0 \leq outflow_{zct} \leq T_{zc} L_z, && \forall z, \forall c, \forall t, \\ & \sum_c (inflow_{zct} - outflow_{zct}) = 0, && \forall z, \forall t. \end{aligned}$$

This definition of flows add some redundancy, but it allows us to penalize inflows with high-voltage transmission losses. This is reflected in the market clearing constraint:

$$q\_clust_{ct} + q\_hydro_{ct} + q\_solar_{ct} + q\_wind_{ct} + sum_z \delta inflow_{zct} - sum_z outflow_{zct} = \frac{d_{ct}}{1-\gamma} \quad \forall z, \forall c, \forall t,$$

where δ represents losses across high-voltage lines and γ represents losses at the distribution level. We set $\delta = 0.025$ and $\gamma = 0.06$.

Appendix Tables and Figures

Table A.1: How Many Years Are Required to Make the Net Present Value of Solar Investment Positive?

Solar Capacity	Annual revenue	Number of years required
Panel A: Without Interconnection		
100 percent	21281.83	More than 100 years
70 percent	61825.18	More than 100 years
30 percent	105787.2	25
Panel B: With Interconnection, without Reinforcement		
100 percent	99676.41	29
70 percent	107323.4	24
30 percent	111234.1	23
Panel C: Actual scenario		
100 percent	106001.2	25

Note: This table shows how many years are required to make the net present value of solar investment positive. See texts in Section 5.2.