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 the existing network was not originally built to accommodate renewables, which creates a mismatch between demand centers and renewable supply. Improving market integration enables renewable expansion in static and dynamic ways. Statically, market integration improves allocative efficiency by gains from trade. Dynamically, it incentivizes new entry of renewables. We show that an event study might capture static effects accurately, but it will tend to underestimate the benefits from transmission expansion if solar investments do not perfectly coincide with the event. We build a structural model of power plant entry and show how to correct for such bias. We apply our framework 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 via the structural model indicates 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 the transmission line, 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] Furthermore, a significant part of the transportation sector is expected to be electrified in the near future. Decarbonizing electricity generation is therefore critical to addressing 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 entry 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.

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 entry 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 entry. 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 51% 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 9% and 4% 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 12% and 5%. 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 entry 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 (2022), which study how the introduction of market-based dispatch mechanisms affected allocative efficiency and enhanced transmission in the US electricity markets. Ryan (2021) also studies the competitive and efficiency effects of transmission in India and Wolak (2015) studies the competitive impacts of transmission in Alberta. 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 entry.

Third, our project relates to recent studies on the role of transmission expansion in renewable energy policy. For example, Fell et al. (2021) find that relaxing transmission constraints between the wind-rich areas and the demand centers in Texas increased the environmental benefit of wind because the transmission expansion allowed wind to offset pollution near highly populated areas. Our study contributes to this literature in two ways. First, we show that transmission expansion incentivizes the new entries of renewables, and therefore, estimating both static and dynamic impacts is key to evaluate the benefit of transmission expansion. Second, in addition to non-market environmental benefits, we evaluate the benefits of renewable expansion on various market outcomes in a wholesale electricity market, including equilibrium prices and generation costs for the whole system. We find that the benefits on the market outcomes are significant because renewable expansion can substantially lower the system-wide prices and costs of electricity when it is combined with transmission expansion.

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*

[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.

- *overestimated if expansion is anticipated but its investment costs ignored.*

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).

We will consider these observations when empirically estimating the impact of transmission expansion in the Chilean context, focusing on how to correct for the under- or overestimation of transmission line benefits using a structural model.

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

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.

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.

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

3.2 Cost-Based Dispatch and Pricing in the Chilean Electricity Market

Similar to other Latin American countries, Chile uses cost-based dispatch to clear demand and supply in its spot market. Power plants submit the technical characteristics of their units as well as natural gas or other input contracts with the input prices to the Load Economic Dispatch Center (CDEC), which is the Independent System Operator (ISO) in Chile. Based on this information, the CDEC computes unit-level start-up cost and variable operating cost everyday and 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 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. Note that cost-based dispatch may not fully eliminate the exercises of market power if large firms could manipulate their reported costs or plant maintenance/outage schedules. However, 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.

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.[8] 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).

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

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 2020.

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 2020.

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 2020.

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 Analysis 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 use insights from Cicala (2022) and take advantage of the fact that we can compute the system-wide "ideal dispatch cost", which is the least possible dispatch cost that can be obtained in the absence of trade constraints within the Chilean electricity markets. Note that we have data on demand, unit-level capacity, and unit-level generation costs every hour. Based on this information, we can identify which units should be dispatched to meet the demand at the lowest system-level cost if there is no trade constraint. We use c_t^* to denote this ideal dispatch cost (USD/MWh) at time t and c_t to denote the observed generation cost per MWh at the system level (i.e., including both SING and SIC).[9]

We then define $c_t - c_t^*$, which shows how much the observed cost deviates from the least possible cost. Our hypothesis is that the market integration increases trade between regions, and therefore, makes c_t closer to c_t^*. To test this hypothesis, we estimate this equation by the OLS:

$$c_t - c_t^* = \beta_1 I_t + \beta_2 R_t + \beta_3 X_t + \theta_m + u_t, \tag{1}$$

[9] Cicala (2022) calculates the least possible dispatch cost within each power control area and call it the "merit-order cost". Our approach is slightly different. We calculate the least possible dispatch cost for the whole Chilean electricity system (as opposed to SING only or SIC only) and call it the "ideal dispatch cost." Our ideal dispatch cost can be considered as the system-wide merit-order cost.

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 to control for seasonality, and u_t is the error term.[10] A key advantage of this approach is that many time-variant factors such as input prices at the plant-unit level will be non-parametric ally controlled by the ideal dispatch cost (c_t^*).

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 1.75 USD/MWh and by 1.14 USD/MWh, respectively. Similarly, column 8 suggests that the interconnection and reinforcement reduced the generation cost in all hours on average by 0.96 USD/MWh and by 1.04 USD/MWh, respectively.

[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 entry 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 5.4, 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 entry. 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 entry of power plants.

To investigate the importance of this point in our empirical context, we examine the entry 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.

[10] Our method is closely related to the method developed by Cicala (2022). An important difference is that we define the ideal dispatch cost c_t^* as the least possible generation cost per MWh at the entire system level including SING and SIC. By contrast, the "merit-order cost" defined in Cicala (2022) is the least possible dispatch cost in each power control area.

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.[11]

These findings from Figure 3 suggest that incorporating the dynamic impacts of market integration (i.e., the impacts on new power plant entry) 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 entry and market integration.

5 Dynamic Analysis of Market Integration

To analyze this long-run effect, we build a structural model of power plant entry. 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.

[11] In Figure A.4, we also examine the entry and exit of thermal plants. We find that the entry of thermal plants slowed down around 2014-2015 and the exit started to increase in this timing. This is suggestive evidence that solar expansion resulted in less entry and more exit of thermal plants because their expected long-run profitability went down as the solar expansion was expected to lower market prices.

5.1 Structural Model

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.[12] 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 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.[13]

Our short-run model is admittedly parsimonious. We initially had envisioned using the mathematical program that

[12] 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. We also have run a weekly and a monthly model, to allow for water to be allocated more flexibly, obtaining similar quantitative results about the value of the transmission expansion.

[13] 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.

the system operator uses on a daily basis, which would fully replicate market clearing under the status quo. We decided to build a simple model because the mathematical program for several reasons. First, this program has thousands of variables and millions of lines, making it computationally very intensive when thinking about counterfactual entry. Second, it is not trivial to understand how to modify the network properly to simulate conditions before and after the reinforcement, as many thousands of lines are modified at the event. Finally, and quite importantly, we do not observe their model for both SING and SIC before they get interconnected. We could improve the model by incorporating startup costs, which would be quite straightforward given that this is a central planner problem, at the cost of some added computational complexity (e.g., see Reguant (2014)).

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:

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

where t indexes a year, h indexes an hour, 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 unit of 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 condition (3).

5.2 Calibration of the Structural Model

Many of the elements in the model are observed in the data, e.g., production costs, demand levels, hydro availability, transmission grid, etc. However, given that our model is stylized, we take several steps to calibrate it. Here we provide an overview, while further details are provided in Appendix B.

Network model To simplify the topography of the network in the Chilean electricity market, we separate the market into five clusters. Any plant in SING belongs to one cluster, as it is a physically isolated entity during the first part of the sample. We assign the provinces in the south of the Maule region to a second cluster. To split the other provinces, where the network is more complex, into three additional clusters. We use a k-means clustering algorithm based on the time series of average province nodal prices, in the spirit of Mercadal (2021).[14]

To calibrate the amount of transmission capacity between these different clusters, we calculate trade flows between our clusters in our data. Based on these trade flows, we set the available capacity to the 95th percentile.[15] We find that this approach captures well the expansion in transmission capacity during our sample period.

Supply curves To model thermal generation and hydro availability, we use supply curves that are estimated based on the hourly plant-level data. For coal, diesel, and other traditional generators, we keep the plant as the unit of observation, and set their marginal costs equal to the bids observed in the data. For SING, we use daily cost. For SIC, we use block cost.

Marginal costs for natural gas combined cycle generators are unfortunately harder to define as the marginal cost depends on the type of long-term contract that is being used, but our data do not specify how much quantity is available under each contract-type.[16] Instead, for natural gas generators, we estimate an hourly cluster-level supply curve based on nodal prices and observed natural gas production. We also include limits to hourly generation set to the minimum and maximum observed generation at each month of sample.

Hydro production is very dependent on expectations of future availability of water, which the Chilean central operator estimates using medium- and long-term forecasting models. Because our model is much more limited, we estimate supply curves based on hydro production and nodal prices at the cluster level, as with natural gas. We regress the observed equilibrium quantities of hydro on equilibrium prices and estimate a month-of-sample supply curve. Additionally, we constrain the amount of water to be used over a given time frame to be equal to the observed water daily use, to reflect the nature of limits to hydro availability.[17] We also include minimum and maximum hydro limits to reflect flow regulations and capacity constraints based on the minimum and maximum observed generation at each month of sample.

Solar potential While our data are very detailed in terms of solar output, we lack data on solar *curtailment*. Solar curtailment is important in our application given the presence of zero prices in the Atacama region before the transmission expansion took place. We take advantage of the extremely predictable solar potential in the Atacama region to estimate solar potential at any given point in time.[18] We estimate capacity factors by month and hour of day base

[14] Our algorithm is simpler than Mercadal (2021), as we do not add an outer loop to discipline the k-means clustering algorithm. Given the topology of the Chilean electricity market, we find that five zones capture well the geographical transmission patterns, at the expense of losing detail about more localized congestion.

[15] We do not use the maximum flow because our clusters do not reflect the exact network configuration, and the maximum flow constructed with our cluster tends to be an outlier.

[16] Differences in prices by contract-type can be very large, as some contracts have a zero marginal cost due to their take-or-pay nature.

[17] We also have solved the model with weekly and monthly water use, allowing more reshuffling of hydro resources. Our overall results remain similar although monthly reshuffling significantly lowers price volatility, counter to our observed data.

[18] Solar potential and availability is very homogeneous in the Atacama desert due to its climatic conditions, (lack of) geographical features, and lack of cloud cover throughout most of the year.

on data after the reinforcement occurred. We use price data at the unit-by-hour level to identify when curtailment occurred by taking advantage the fact that curtailment makes price equal to zero. We use these capacity factors times the installed capacity to back out potential solar output.

Investment costs Additionally, we need to calibrate the investment equation (3) of the long run model, which is not observed in the data. There are two parameters that are potentially unobserved, the cost of solar investment (ρ) and the annual interest rate (r). We use $r = -0.0583$, which is the Chilean government's discount rate for their public investment projects (Moore et al., 2020). We then estimate ρ by imposing that the observed solar level investment is consistent with a zero profit condition based on average profitability during periods 2 and 3 in the sample is satisfied at the observed level of investment and with an expanded grid. Using this methodology, we estimate the cost of solar to be around 1.5 million per MW installed.

5.2.1 Goodness of fit

While the final 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. Table A.7 in the Appendix shows that we also match well the production attributed to each generation source across the three periods of study, although natural gas generation is somewhat underestimated in favor of other generators. Our baseline model successfully captures an increase in the production of renewable generation when transmission gets expanded, and matches well the observed percentage increases in the data.

[Figure 7 about here]

By construction, as an empirical strategy for our calibration, our long run investment model is consistent with the data. However, our model is not a careful representation of the investors' expectations and application process to build solar in this market, which is beyond the scope of our model. Even with such a stylized model, our estimated cost per MW installed are on a similar order of magnitude as reported solar panel installation costs. More concretely, we use data on reported completion dates and costs for large-scale solar installations from a quarterly survey run by CLAPES UC-CBC.[19] For a total of 107 completed projects, average costs are around 1.95 million dollars per MW.[20]

5.3 Simulating the Benefits from Transmission

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*.

[19] See https://www.cbc.cl/ppicbc/

[20] Our lower estimated costs could be in part driven by the unusually low fossil fuel prices during the end of our sample, which reduced the profitability of solar panels significantly.

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 entry—some entry 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 (as a percentage) that would not have occurred in the absence of market integration. We define the entry threshold as a percentage of the total because solar production in the Atacama desert is very homogeneous, and therefore the exact location of the solar panels is not as relevant as in other applications (e.g., more heterogeneous areas or wind power). As we reduce the entry 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 entry have to be excluded to make the solar investment profitable in the absence of market integration.We show the result in Appendix table A.2. In the absence of market integration, 75% 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 25 years. Thus, our third scenario is the market equilibrium with no market integration and a 75% 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 equilibrium in a dynamic sense because solar power would be unprofitable investment. With the dynamic consideration (i.e. 75% 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 market integration, solar generation would be less than the actual scenario by 17% in the static case and 51% if we incorporate the dynamic impact on solar plant entry. 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% (9% at noon, an hour with high solar generation). However, the dynamic gross benefits are 5% (12% at noon). The results from that observation also suggest that 4% is an upper bound on the *net* benefits of investment (accounting for solar investment costs).

[Table 3 about here]

The system-level prices suggest that market integration can successfully reduce prices. However, this is not true for all regions, with Atacama having much lower prices in the absence of market integration. 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 (1.58 USD/MWh in column 2). This is because the static approach ignores the fact that some solar entry 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.[21]

5.4 Estimating a Corrected Event Study

We generate the time series from our model to perform event study regressions. However, the ability to calculate investment under different scenarios allows us to generate a time series regression in which investment coincides with

[21] 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.

the event, which would remove the bias concerns explained in Section 2. We run regressions analogous to Table 2 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 analyze the two event studies in our data more closely, we add the computation of the investment that would occur if only the interconnection would have been built, but not the reinforcement. We find that 30% of solar entry would not be profitable without the reinforcement. We create a time series of average costs that has reduced solar investment before the interconnection, it goes to partial investment in the interim period, and only achieves full investment once the reinforcement happens. This allows us to compute the changes in dynamic and static gains when one moves from the interconnection to the reinforcement period.

In Table 4, we present a comparison of the regression estimates. To make the comparison easier, we present here the comparison of the event coefficients (interconnection and reinforcement). The full regression results are presented in the Appendix in Table A.5.

[Table 4 about here]

With the conventional static event study analysis without dynamic correction, the anticipated investment in solar panels leads to an understatement of the benefits of the line. Column 1 indicates that costs are reduced by 1.40 and 0.68 $/MWh thanks to the interconnection and reinforcement, respectively. However, Column 2, which has a dynamic correction, increases such a reduction to 2.72 and 1.97, respectively. These are sizeable changes in the benefits of the line. Comparison between columns 1 and 2 and between columns 4 and 5 suggests that accounting for the dynamic benefits of the lines substantially increases the estimates of cost reductions.This highlights some of the added benefits that might be underestimated by a more naïve event-study design.

6 Cost-Benefit Analysis of the Transmission Investments

According to the Chilean government, the costs of constructing the interconnection and the reinforcement were $860 million and $1,000 million respectively (Raby, 2016; Isa-Interchile, 2022). In this section, we compare these costs with the net present value of the long-run benefit of these transmission investments to provide a cost-benefit analysis.[22]

In a short-run analysis, the benefit of the market integration can be expressed by the improvement in the allocative efficiency, which is the sum of the changes in consumer surplus and producer surplus. In a long-run analysis, it is important to consider how the fixed costs of power plant investments (e.g., the new entries of solar plants) will be paid. Because the Chilean electricity market uses the cost-based regulation, we consider that firms use their cumulative

[22]We consider a cost-benefit of the interconnection and reinforcement together in this section. We provide a cost-benefit of the interconnection by itself in Figure A.2 in the appendix.

producer surplus to recover their fixed costs. Therefore, the long-run net benefit of market integration is simply the change in consumer surplus.[23]

We use the results from the counterfactual simulations in Table 3 to calculate the change in consumer surplus. For each year, month, hour, and cluster, we obtain the market equilibrium prices for two scenarios—"actual scenario" (i.e., the scenario with the interconnection and reinforcement) and "no market integration scenario." We obtain the change in consumer surplus by multiplying electricity demand with the difference in the prices between "actual scenario" and "no market integration." Finally, we calculate the net present value of this consumer surplus with a range of assumptions on the discount rate.

In Figure 11, we use a wide range of discount rates to show how long it takes to recover the costs of the transmission investments. The first line ("without dynamic correction") shows the result in which we do not incorporate the dynamic impact on solar investment, whereas the second line ("with dynamic correction") incorporates the dynamic impact. These two lines indicate that ignoring the dynamic impact substantially understates the benefit of the transmission investments.

[Figure 11 about here]

An additional benefit of the market integration in our context is the reduction in negative environmental externality. The market integration increased renewable generation, which might have replaced some thermal generation. This implies that the market integration might have reduced both of the global pollutants such as CO_2 and the local pollutants such as SO_2 and NO_X. Our counterfactual simulations allow us to quantify the difference in electricity production at the unit-by-hour level between "actual scenario" and "no market integration scenario." We use this information to calculate the reduction in electricity production from each type of thermal plants such as coal and natural gas. We combine this information with the estimates of the negative externality (USD/MWh) by power plant types in Greenstone and Looney (2012) and Carleton and Greenstone (2021). [24] The third line in Figure 11 suggests that with this environmental benefit, the costs of interconnection and reinforcement can be recovered in 10 years with the Chilean government's discount rate at 5.83% (Moore et al., 2020).[25]

It is important to note that our calculation is likely to understate the benefit of the market integration at least for three reasons. First, coal and natural gas prices were lower than the historical average in our sample period. If these fuel prices come back to historical averages in the future, the benefit of renewables would be larger than our calculation.

[23] An alternative approach is to include both consumer and producer surplus and subtract the fixed cost of power plants. Our data provide upfront costs of recently-built solar plants. A challenge is that the fixed cost of power plants for the "no market integration" scenario is unclear. In reality, new non-renewable plants need to be built in this scenario for the next few decades, but it is difficult to predict these costs. In Figure A.3, we take a conservative approach by assuming that the fixed cost of non-renewable power plants are zero, which provides the lower bound of the benefit-cost ratio.

[24] Greenstone and Looney (2012) estimate that the non-carbon external cost is 3.4 cents per kWh for coal generation and 0.2 cents per kWh for natural gas generation.

[25] In 2015, the government of Chile held a public auction for the construction of the transmission line. In this auction, one objective is to minimize the cost of construction that is paid by consumers in the tariff associated with electric transmission.

Second, our calculation includes the entries of solar plants only up to the end of our sample period and does not include additional entries of solar plants in the subsequent years. Because these additional entries were unlikely to occur in the absence of market integration, this is another reason why our benefit calculation can be underestimated. Finally, prior to the renewable expansion, Chile has been relying on imports of natural gas and coal to generate large amount of electricity, and it has been an energy security problem. Therefore, renewable expansion provided a benefit of energy security for the country, which is not incorporated in our calculation.

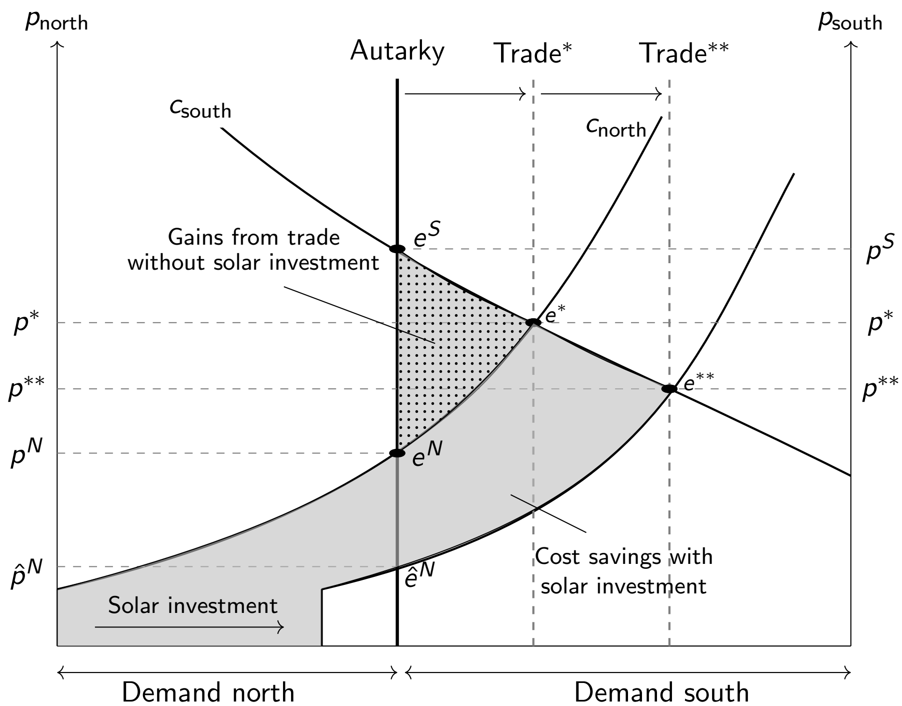
7 Conclusions

We present a simple theoretical model that emphasizes 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 entry of renewables plants. We highlight how a traditional event study methodology could miss the full dynamic impact. To quantify these theoretical predictions, we build a structural model of solar investment and apply it to the Chilean electricity market, which underwent a recent increase in market integration—two fully separated markets were integrated into one market in 2017 and further reinforced in 2019.

Empirically, 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 using an event study methodology would significantly understate the benefits of market integration, including its impacts on allocative efficiency and renewable expansion.

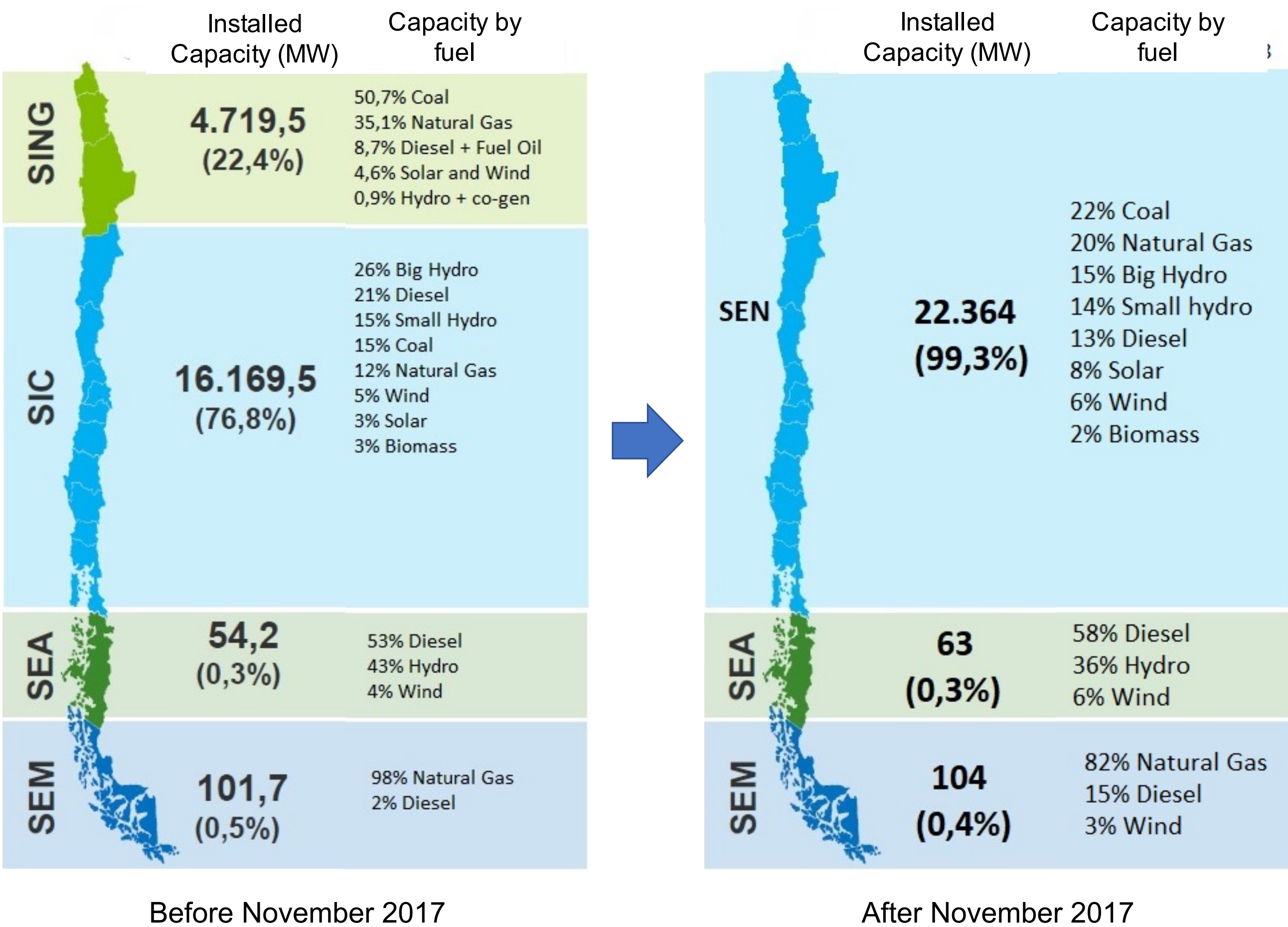
Figures

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 entry 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 entry 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 entry of solar plants.

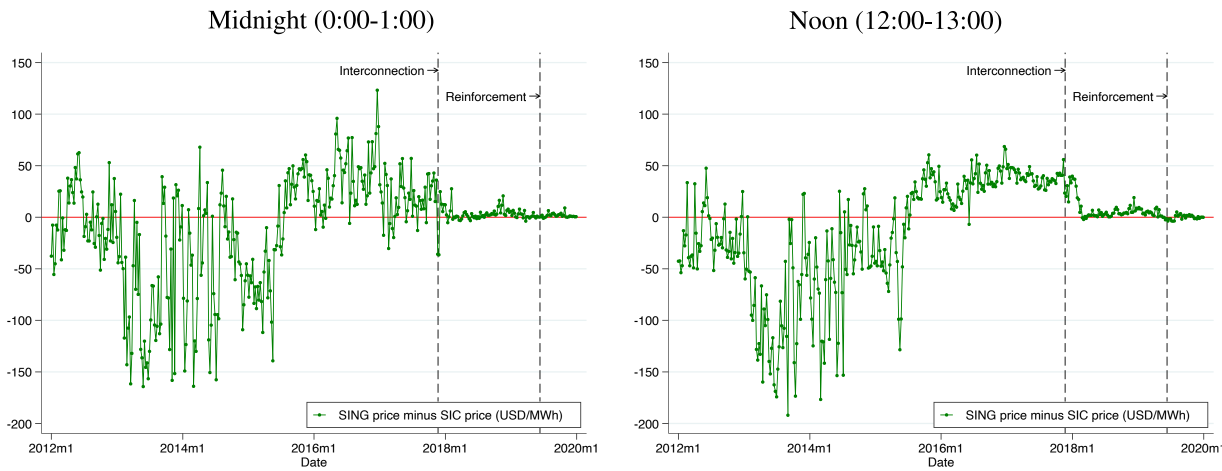
Figure 2: Market Integration in the Chilean Electricity Markets



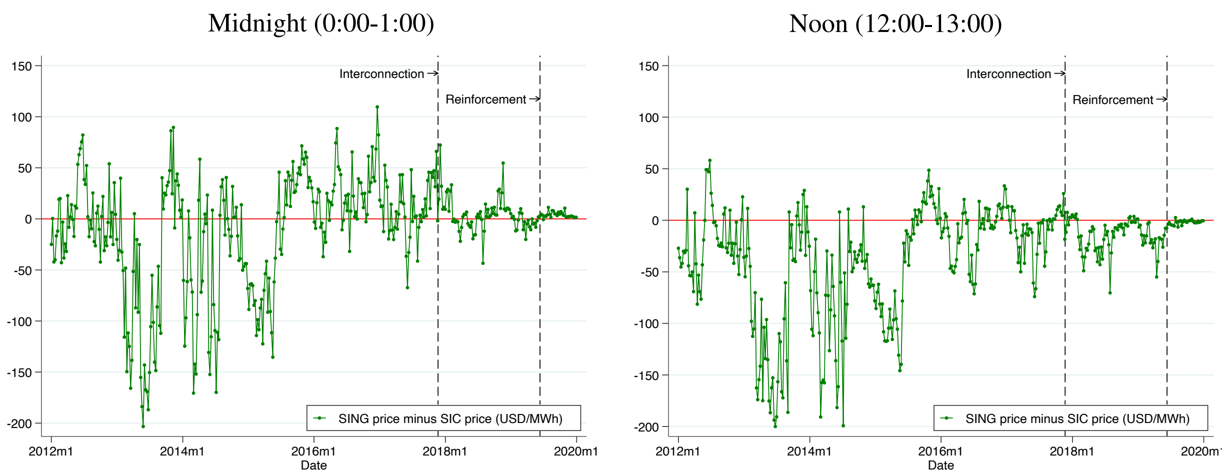
Note: The two largest electricity markets in Chile (SING and SIC) were integrated to become one market (SEN) in November 2017.

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)

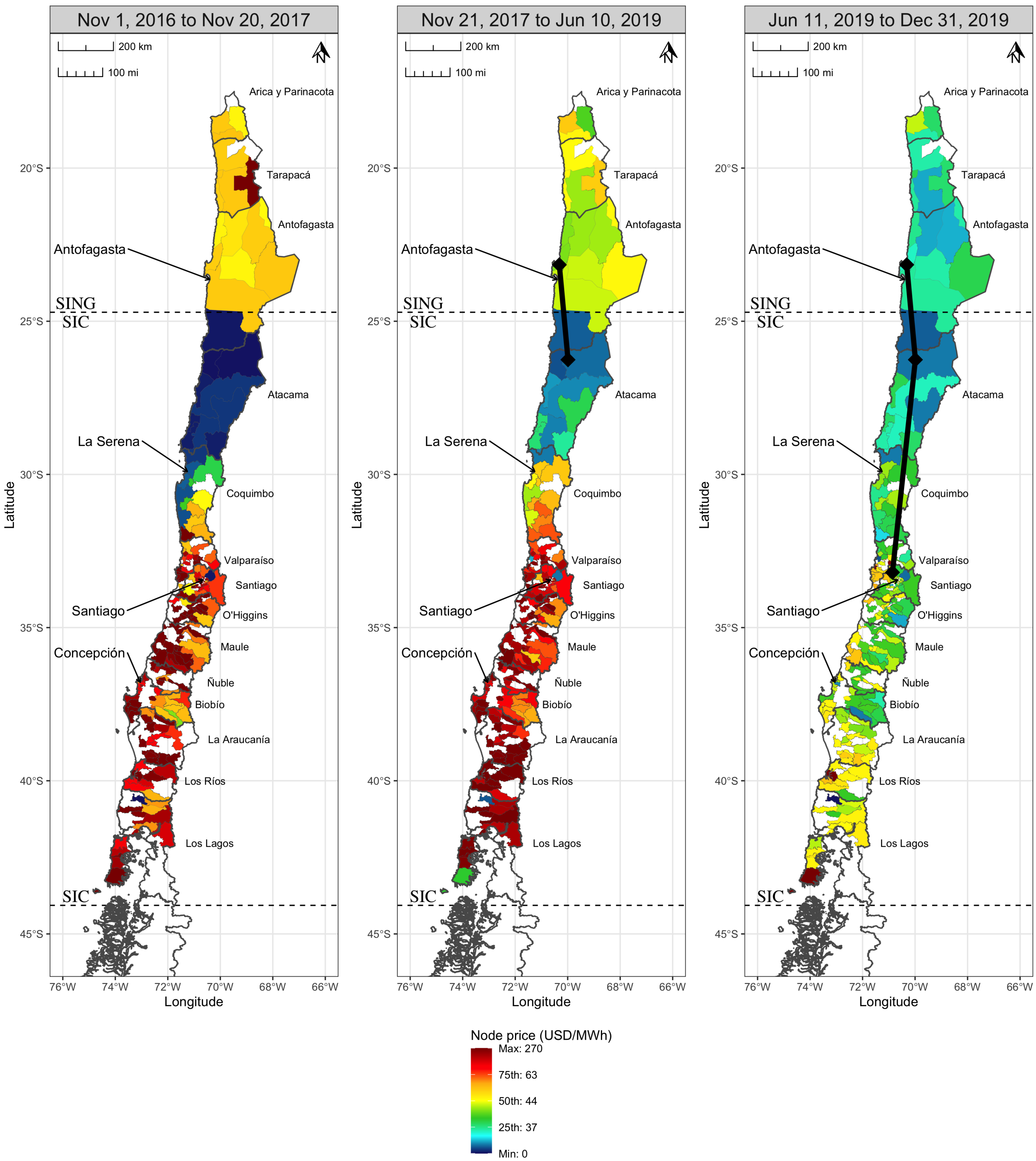


Panel B: All regions



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.

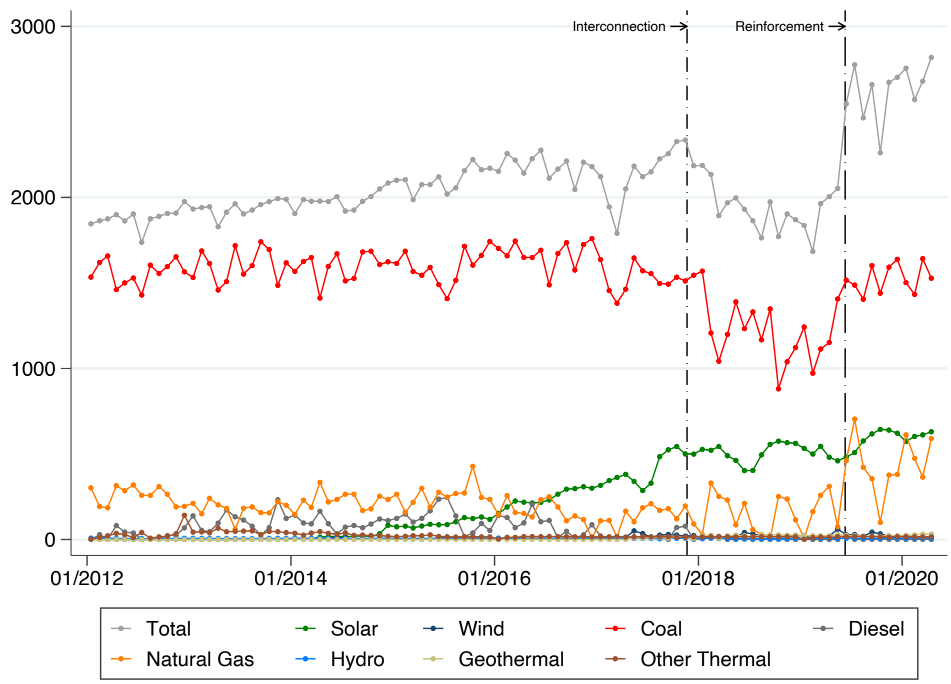
Figure 4: Impacts of Market Integration on Spatial Variation in Electricity Prices



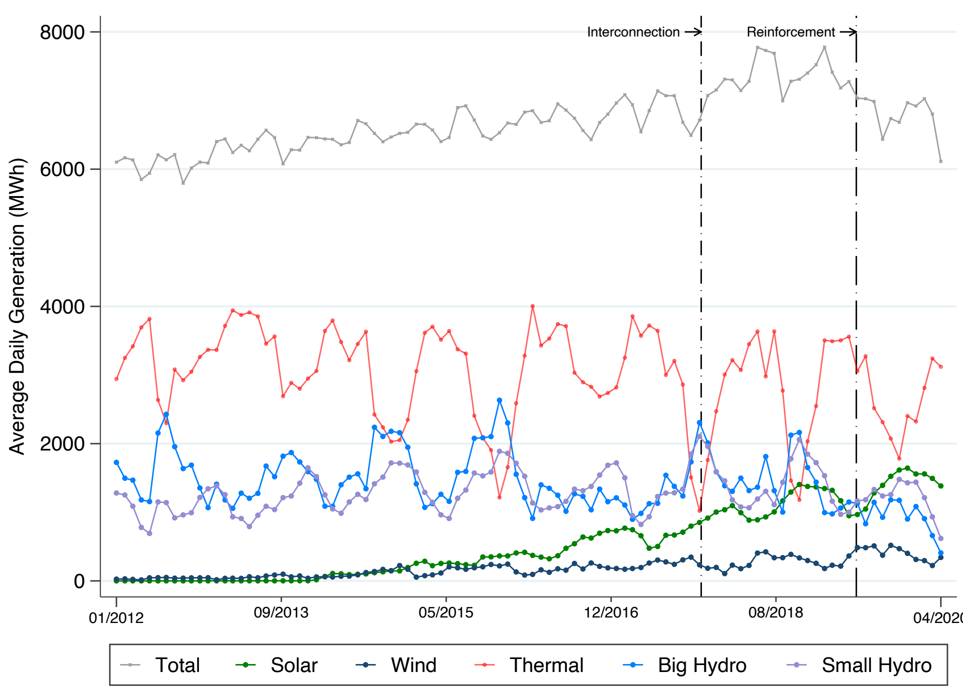
Note: These heat maps examine spatial heterogeneity in wholesale electricity prices. We calculate the province-level average node prices and make heat maps for the three time periods: 1) before the interconnection, 2) after the interconnection but before the reinforcement, and 3) after the reinforcement. 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)

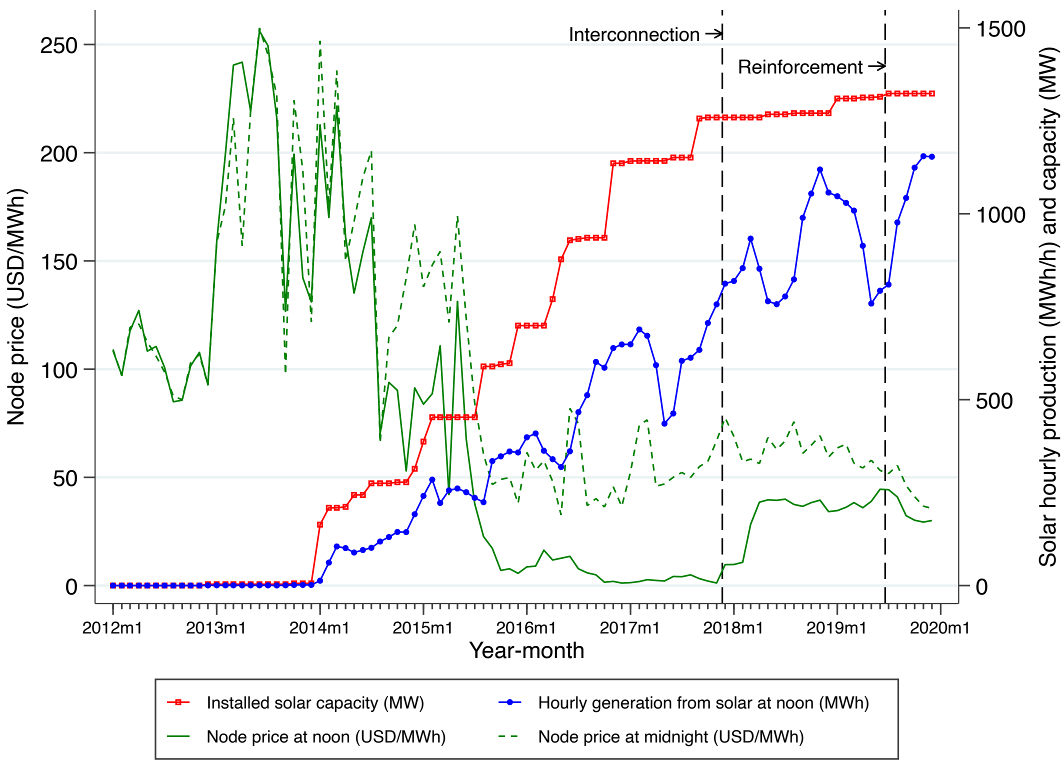


Panel B: SIC (south)



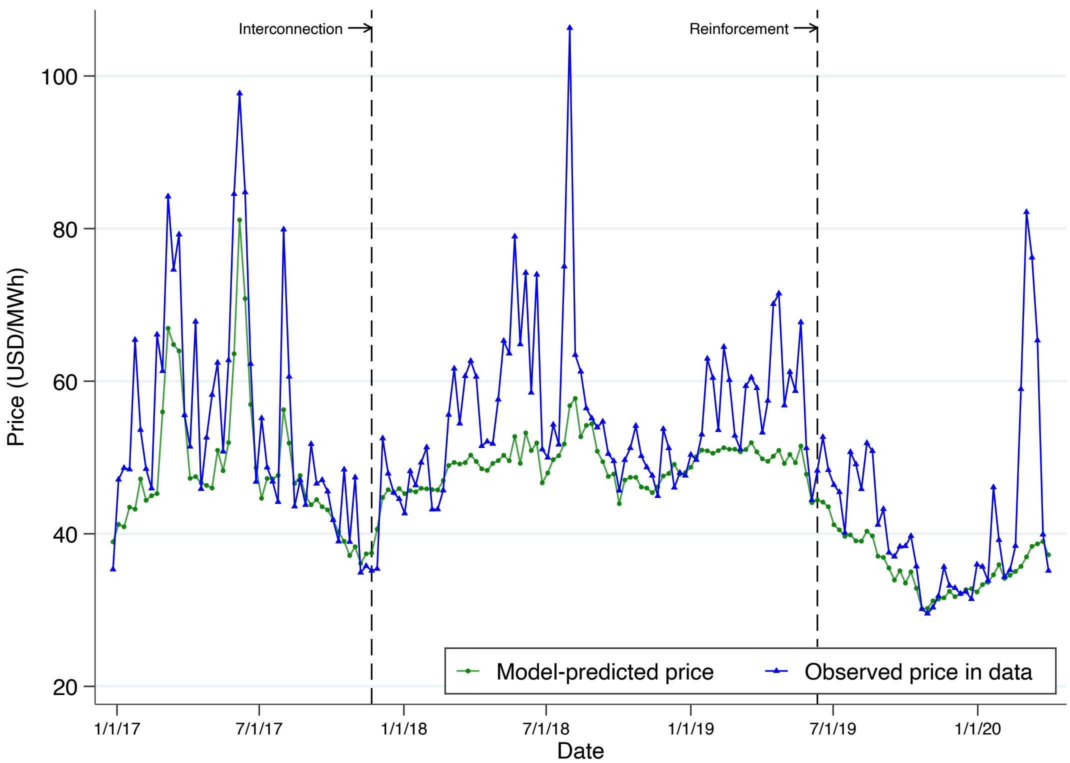
Note: This figure shows the average daily generation (MWh) by fuel type over the calendar months.

Figure 6: Impacts of Market Integration on Renewable Expansion



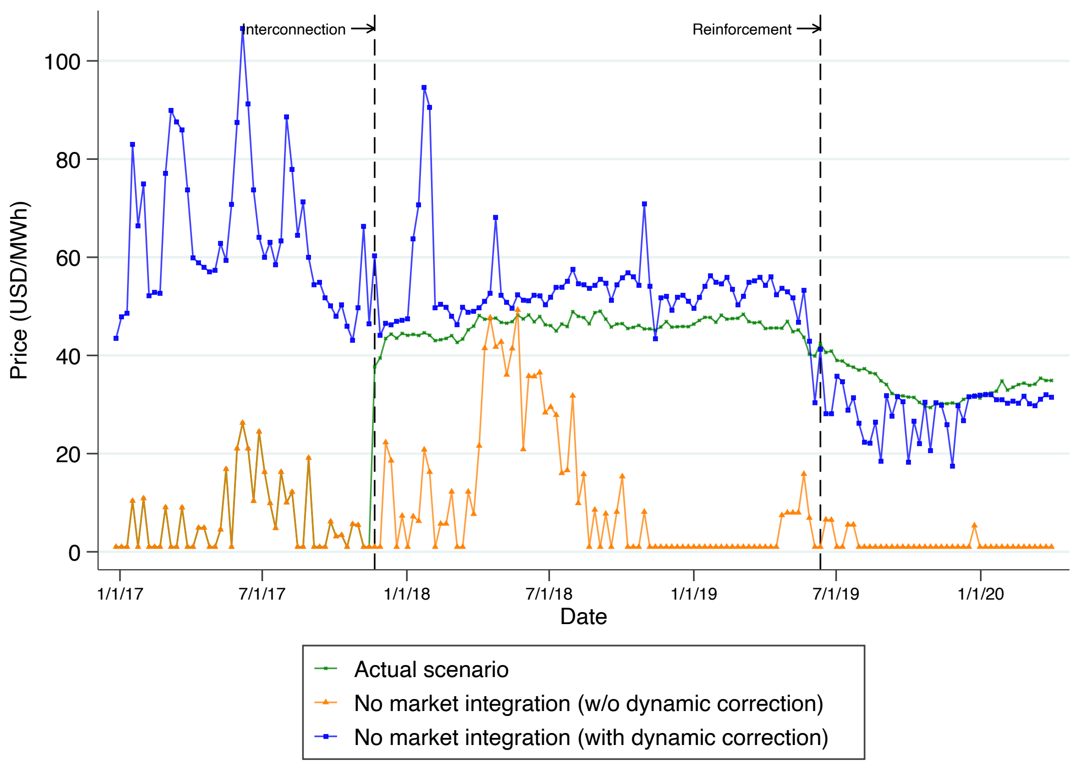
Note: This figure shows the cumulative installed capacity of solar plants, average hourly generation for each month, and node prices for these plants at noon and midnight.

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



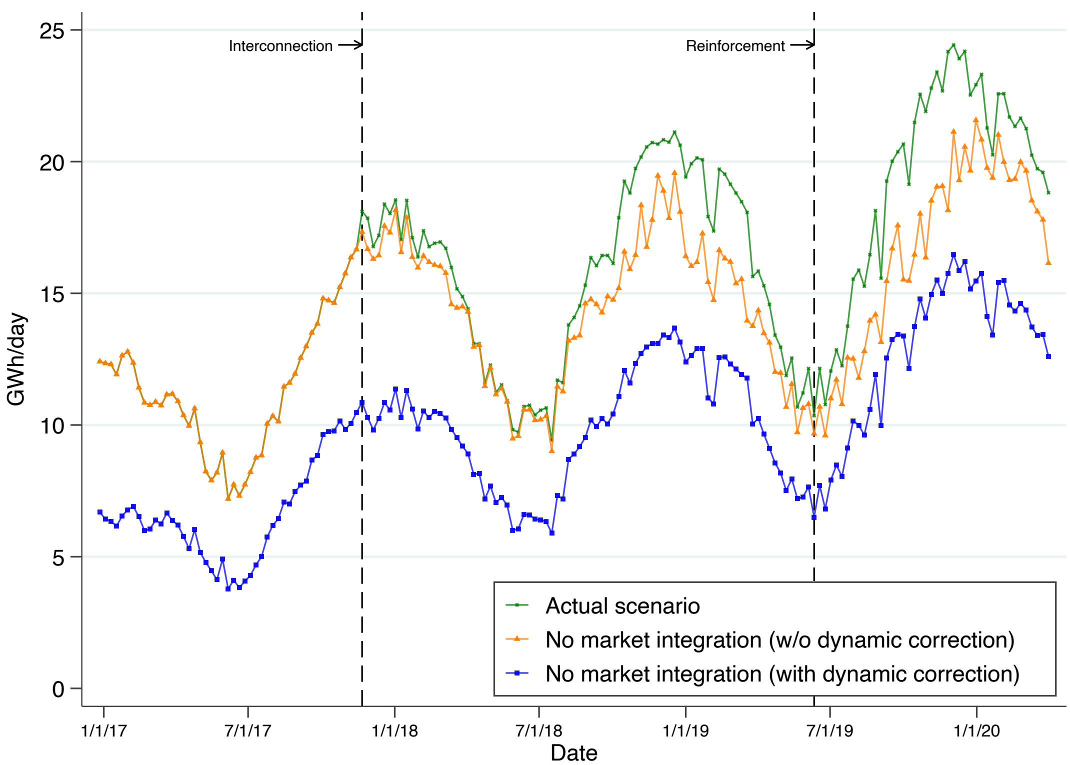
Note: This figure compares the price predicted by the structural model described in Section 5 and actual prices in the data. Each dot represents the weekly average of hourly node prices from all nodes, weighted by the generation at the node level.

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



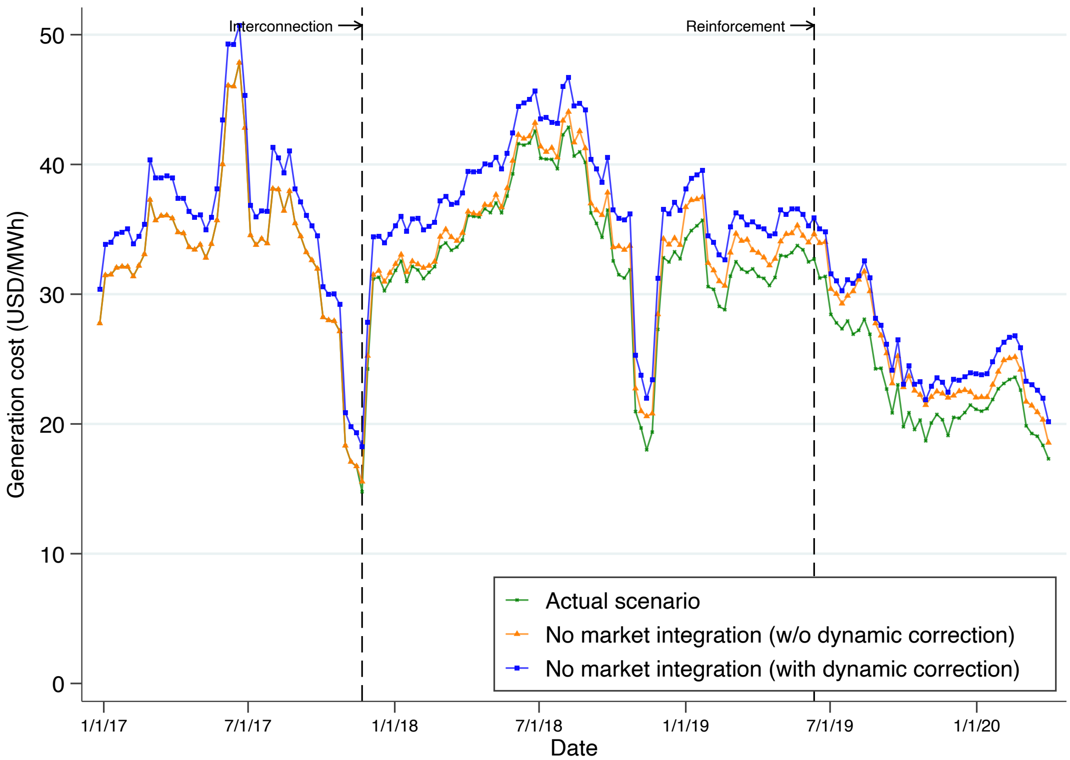
Note: We use the structural model and counterfactual simulations described in Section 5.3 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second 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 entry—some entry would not happen in the absence of market integration because such investment would become unprofitable. This figure presents the wholesale electricity prices (USD/MWh) for these three scenarios.

Figure 9: Counterfactual Simulation Results: Solar Generation



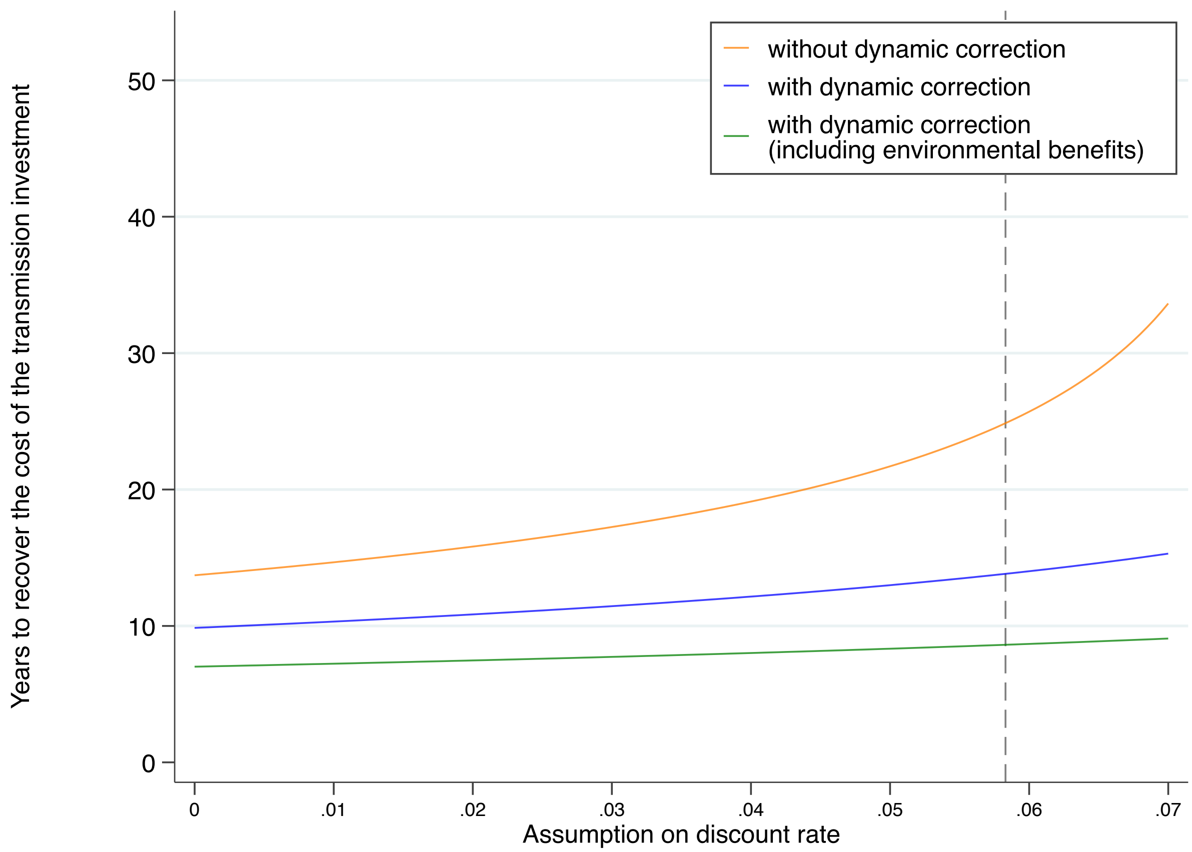
Note: We use the structural model and counterfactual simulations described in Section 5.3 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second 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 entry—some entry 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 5.3 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 entry—some entry 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 11: Cost-Benefit Analysis of Investments in the Transmission Lines



Note: This figure shows how long it takes to recover the cost of transmission investment based on the net present value of the benefit of market integration. The dashed vertical line (0.0583) shows the Chilean government's discount rate for their public investment projects.

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 Event Study Analysis of the Impact of Market Integration

Dependent Variable: Generation Cost - Ideal Dispatch Cost (USD/MWh)

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.42	-1.72	-1.73	-1.75	-1.00	-1.07	-1.07	-0.96
	(0.15)	(0.18)	(0.18)	(0.19)	(0.12)	(0.14)	(0.14)	(0.14)
1(After the reinforcement)	-2.25	-0.87	-0.95	-1.14	-1.58	-0.83	-0.83	-1.04
	(0.18)	(0.35)	(0.36)	(0.37)	(0.14)	(0.26)	(0.27)	(0.27)
Coal price [USD/ton]		0.02	0.02	0.02		0.00	0.00	0.00
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			-4.26	-4.39			-0.01	0.33
			(4.21)	(4.20)			(3.18)	(3.15)
Hydro availability				-0.26				-0.43
				(0.12)				(0.10)
Scheduled demand (GWh)				0.20				0.02
				(0.10)				(0.10)
Constant	6.58	3.25	3.71	2.76	5.88	3.93	3.93	4.92
	(0.12)	(0.79)	(0.91)	(1.12)	(0.10)	(0.60)	(0.69)	(0.95)
Mean of dep var	5.17	5.17	5.17	5.17	4.89	4.89	4.89	4.89
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R^2	0.26	0.56	0.56	0.56	0.21	0.58	0.58	0.59

Note: This table shows the results of the regression described in equation (1). The dependent variable is the difference between the observed hourly generation cost per MWh and the ideal dispatch cost (i.e., the least possible generation cost that can be obtained without any trade constraints).

Table 3: Counterfactual Simulation Results: Impacts of Market Integration with Dynamic Correction

	(1)	(2)	(3)	(4)	(5)
	Actual	No market integration		Impacts of integration	
	Market integration	Without dynamic correction	With dynamic correction	(1)-(2) Without correction	(1)-(3) With correction
Solar generation (GWh/day)	19.37	16.60	12.80	2.77 (+17%)	6.57 (+51%)
Generation cost (USD/MWh): all hours	26.43	27.45	27.91	-1.02 (-4%)	-1.48 (-5%)
Generation cost (USD/MWh): hour 12	23.11	25.28	26.40	-2.17 (-9%)	-3.29 (-12%)
Daily price in all regions (USD/MWh)	36.35	38.18	38.89	-1.83 (-5%)	-2.54 (-7%)
Price at noon in all regions (USD/MWh)	35.48	37.33	39.19	-1.84 (-5%)	-3.71 (-9%)
Price at noon in Atacama (USD/MWh)	33.90	1.58	28.81	32.32 (+2,040%)	5.09 (+18%)
Price at noon in Santiago (USD/MWh)	36.68	43.58	43.59	-6.89 (-16%)	-6.91 (-16%)
Price difference (Santiago - Atacama)	2.78	41.99	14.78	-39.21 (-93%)	-12.00 (-81%)

Note: This table shows the counterfactual simulation results in Section 5.3. 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 25% of solar investment is present).

Table 4: Dynamic Correction for the Event Study Analysis

	Hour 12			All hours		
	Event study analysis		Counterfactual simulation	Event study analysis		Counterfactual simulation
	(1)	(2)	(3)	(4)	(5)	(6)
Dynamic correction:	No	Yes	Yes	No	Yes	Yes
1(After the interconnection)	-1.40	-2.72	-2.36	-0.60	-1.18	-1.05
	(0.07)	(0.09)		(0.04)	(0.05)	
1(After the reinforcement)	-0.68	-1.97	-1.58	-0.29	-0.76	-0.64
	(0.15)	(0.17)		(0.07)	(0.09)	

Note: This table summarizes results from Table A.5 (event study analysis with and without dynamic correction) and Table A.6 (counterfactual simulation with dynamic correction). Columns 1 and 4 show the estimates from the event study analysis without dynamic correction. In columns 2 and 5, we shift the timing of solar investment so that it occurs right after the interconnection and reinforcement (i.e., correct for anticipatory investment effects), use our structural model to obtain market outcomes, and re-run the event study analysis. In columns 4 and 6, we compare the results of the event study analysis with dynamic correction to the results from counterfactual simulation with dynamic correction.

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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.

$\square$

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.

$\square$

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. $\square$

B Short-run dispatch model details

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 coal power plant, at most equal to the plant's capacity.
- q_gas_{it}: Natural gas generation at each cluster.
- 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 and usage constraints (hourly min, hourly max, and total availability).
- 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:

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

The costs from thermal generation come from the regulatory data. For SING, we use daily cost. For SIC, we use block cost. 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.[26] 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.[27]

[26] 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.

[27] 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:

$$\sum_{i \in c} q_{it} + q\_gas_{ct} + q\_hydro_{ct} + q\_solar_{ct} + q\_wind_{ct} + \sum_z \delta inflow_{zct} - \sum_z outflow_{zct} = \frac{d_{ct}}{1-\gamma} \quad \forall z, \forall c, \forall t,$$

where δ represents losses across high-voltage lines and γ represents losses at the distribution level. We set $\delta = 0.025$ and $\gamma = 0.08$.

Appendix Tables and Figures

Table A.1: Trade capacity

	Period 1	Period 2	Period 3
Line 1	0.00	594.17	822.18
Line 2	313.68	586.28	1606.50
Line 3	322.35	580.62	1707.15
Line 4	1456.41	1520.62	1496.12

Table A.2: 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% capacity	26293.4	More than 100 years
70% capacity	67638.3	More than 100 years
30% capacity	107529.4	26
25% capacity	111122.9	25
Panel B: Without Reinforcement		
100% capacity	104711.9	28
70% capacity	109326.4	25
30% capacity	112990.0	24
25% capacity	113423.0	24
Panel C: Actual scenario		
100% capacity	109094.1	25

Note: This table shows how many years are required to make the net present value of solar investment positive. See texts in Section 5.3.

Table A.3: Event Study Analysis With and Without Dynamic Correction

Panel A: Without Dynamic Correction

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.44	-1.35	-1.35	-1.40	-0.67	-0.59	-0.59	-0.60
	(0.06)	(0.08)	(0.08)	(0.07)	(0.03)	(0.04)	(0.04)	(0.04)
1(After the reinforcement)	-0.32	-0.41	-0.41	-0.68	-0.07	-0.24	-0.25	-0.29
	(0.07)	(0.15)	(0.15)	(0.15)	(0.03)	(0.07)	(0.07)	(0.07)
Coal price [USD/ton]		-0.00	-0.00	-0.00		-0.00	-0.00	-0.00
		(0.00)	(0.00)	(0.00)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			0.16	-0.09			-0.07	-0.00
			(1.77)	(1.67)			(0.88)	(0.86)
Hydro availability				-0.38				-0.10
				(0.05)				(0.03)
Scheduled demand (GWh)				0.44				0.13
				(0.04)				(0.03)
Constant	1.83	1.60	1.59	-0.94	0.78	0.95	0.96	0.24
	(0.05)	(0.33)	(0.38)	(0.44)	(0.02)	(0.16)	(0.19)	(0.26)
Mean of dep var	0.77	0.77	0.77	0.77	0.31	0.31	0.31	0.31
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R^2	0.44	0.59	0.59	0.64	0.42	0.52	0.52	0.54

Panel B: With Dynamic Correction

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-2.78	-2.71	-2.70	-2.72	-1.23	-1.18	-1.18	-1.18
	(0.07)	(0.09)	(0.09)	(0.09)	(0.03)	(0.05)	(0.05)	(0.05)
1(After the reinforcement)	-1.60	-1.70	-1.64	-1.97	-0.59	-0.73	-0.71	-0.76
	(0.08)	(0.17)	(0.17)	(0.17)	(0.04)	(0.09)	(0.09)	(0.09)
Coal price [USD/ton]		-0.00	-0.00	-0.00		-0.00	-0.00	-0.00
		(0.00)	(0.00)	(0.00)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			3.03	2.80			0.83	0.91
			(2.04)	(1.96)			(1.05)	(1.04)
Hydro availability				-0.44				-0.11
				(0.05)				(0.03)
Scheduled demand (GWh)				0.35				0.11
				(0.05)				(0.03)
Constant	4.45	4.28	3.96	2.31	1.87	2.06	1.97	1.42
	(0.05)	(0.38)	(0.44)	(0.52)	(0.03)	(0.20)	(0.23)	(0.32)
Mean of dep var	2.22	2.22	2.22	2.22	0.90	0.90	0.90	0.90
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R^2	0.75	0.82	0.82	0.83	0.69	0.75	0.75	0.75

Table A.4: Static Event Study Analysis of the Impact of Market Integration

Dependent Variable: Generation Cost (USD/MWh)

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.50	-1.70	-1.71	-1.72	-1.05	-1.07	-1.07	-0.97
	(0.15)	(0.19)	(0.19)	(0.19)	(0.12)	(0.14)	(0.14)	(0.14)
1(After the reinforcement)	-1.69	-0.83	-0.91	-1.12	-1.37	-0.87	-0.87	-1.07
	(0.21)	(0.35)	(0.36)	(0.37)	(0.17)	(0.26)	(0.27)	(0.27)
Ideal dispatch cost	1.06	1.02	1.02	1.02	1.02	0.98	0.98	0.99
	(0.01)	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.02)
Coal price [USD/ton]		0.02	0.02	0.02		0.01	0.01	0.01
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			-4.47	-4.59			0.20	0.51
			(4.21)	(4.20)			(3.18)	(3.15)
Hydro availability				-0.27				-0.43
				(0.12)				(0.10)
Scheduled demand (GWh)				0.17				0.04
				(0.10)				(0.10)
Mean of dep 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
R^2	0.93	0.96	0.96	0.96	0.94	0.97	0.97	0.97

Table A.5: Event Study Analysis With and Without Dynamic Correction

Panel A: Without Dynamic Correction

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-1.50	-1.28	-1.28	-1.32	-0.70	-0.59	-0.59	-0.60
	(0.05)	(0.08)	(0.08)	(0.07)	(0.03)	(0.04)	(0.04)	(0.04)
1(After the reinforcement)	0.15	-0.28	-0.29	-0.61	0.04	-0.19	-0.20	-0.25
	(0.07)	(0.14)	(0.15)	(0.14)	(0.04)	(0.07)	(0.07)	(0.07)
Ideal dispatch cost	1.05	1.06	1.06	1.05	1.01	1.02	1.02	1.02
	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)	(0.00)
Coal price [USD/ton]		-0.01	-0.01	-0.01		-0.01	-0.01	-0.01
		(0.00)	(0.00)	(0.00)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			-0.54	-0.67			-0.34	-0.23
			(1.71)	(1.63)			(0.87)	(0.86)
Hydro availability				-0.41				-0.10
				(0.05)				(0.03)
Scheduled demand (GWh)				0.35				0.10
				(0.04)				(0.03)
Mean of dep var	31.72	31.72	31.72	31.72	34.29	34.29	34.29	34.29
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R^2	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00

Panel B: With Dynamic Correction

	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	-2.84	-2.64	-2.64	-2.62	-1.24	-1.18	-1.18	-1.18
	(0.06)	(0.09)	(0.09)	(0.09)	(0.03)	(0.05)	(0.05)	(0.05)
1(After the reinforcement)	-1.16	-1.58	-1.53	-1.89	-0.55	-0.68	-0.67	-0.72
	(0.09)	(0.17)	(0.17)	(0.17)	(0.05)	(0.09)	(0.09)	(0.09)
Ideal dispatch cost	1.05	1.05	1.05	1.06	1.00	1.02	1.02	1.02
	(0.00)	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)	(0.00)	(0.01)
Coal price [USD/ton]		-0.01	-0.01	-0.01		-0.01	-0.01	-0.01
		(0.00)	(0.00)	(0.00)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			2.38	2.11			0.56	0.67
			(2.00)	(1.92)			(1.04)	(1.04)
Hydro availability				-0.48				-0.11
				(0.05)				(0.03)
Scheduled demand (GWh)				0.24				0.08
				(0.05)				(0.03)
Mean of dep var	33.17	33.17	33.17	33.17	34.89	34.89	34.89	34.89
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1041	1041	1041	1041	1041	1041	1041	1041
R^2	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00

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

Table A.6: Counterfactual Simulation: Impacts of the Interconnection and Impacts of the Reinforcement

Panel A: Impact of the Interconnection

	(1)	(2)	(3)	(4)	(5)
		No interconnection		Impacts of interconnection	
	Interconnection only	Without dynamic correction	With dynamic correction	(1)-(2) Without correction	(1)-(3) With correction
Solar generation (GWh/day)	13.41	13.10	9.85	0.31 (+2%)	3.56 (+36%)
Generation cost (USD/MWh): all hours	37.15	37.48	38.20	-0.33 (-1%)	-1.05 (-3%)
Generation cost (USD/MWh): hour 12	34.71	35.16	37.07	-0.45 (-1%)	-2.36 (-6%)
Daily price in all regions (USD/MWh)	49.46	50.05	50.85	-0.58 (-1%)	-1.39 (-3%)
Price at noon in all regions (USD/MWh)	50.17	50.60	52.37	-0.43 (-1%)	-2.20 (-4%)
Price at noon in Atacama (USD/MWh)	47.06	35.60	53.35	11.46 (+32%)	-6.29 (-12%)
Price at noon in Santiago (USD/MWh)	52.29	54.50	55.09	-2.20 (-4%)	-2.79 (-5%)
Price difference (Santiago - Atacama)	5.23	18.90	1.74	-13.66 (-72%)	3.50 (+201%)

Panel B: Impact of the Reinforcement

	(1)	(2)	(3)	(4)	(5)
	Actual	Interconnection only		Impacts of reinforcement	
	Interconnection and reinforcement	Without dynamic correction	With dynamic correction	(1)-(2) Without correction	(1)-(3) With correction
Solar generation (GWh/day)	18.48	18.44	15.99	0.04 (+0%)	2.48 (+16%)
Generation cost (USD/MWh): all hours	27.14	27.43	27.78	-0.29 (-1%)	-0.64 (-2%)
Generation cost (USD/MWh): hour 12	23.91	24.61	25.49	-0.70 (-3%)	-1.58 (-6%)
Daily price in all regions (USD/MWh)	36.60	37.91	38.04	-1.32 (-3%)	-1.45 (-4%)
Price at noon in all regions (USD/MWh)	35.88	37.82	38.04	-1.94 (-5%)	-2.16 (-6%)
Price at noon in Atacama (USD/MWh)	34.03	29.87	32.02	4.17 (+14%)	2.01 (+6%)
Price at noon in Santiago (USD/MWh)	37.22	41.37	41.39	-4.15 (-10%)	-4.16 (-10%)
Price difference (Santiago - Atacama)	3.19	11.51	9.37	-8.32 (-72%)	-6.18 (-66%)

Table A.7: Generation ratio

	Renewable	Hydro	Coal	Natural gas	Other thermal	Total
Pre-interconnection						
Observed	9.9%	26.8%	39.9%	18.7%	4.7%	100.0%
Model-predicted	10.4%	26.8%	39.2%	15.8%	7.7%	100.0%
Post-interconnection, Pre-reinforcement						
Observed	12.4%	29.7%	37.3%	16.4%	4.2%	100.0%
Model-predicted	12.7%	29.6%	35.3%	14.6%	7.8%	100.0%
Post-reinforcement						
Observed	15.9%	27.2%	36.2%	17.4%	3.3%	100.0%
Model-predicted	16.0%	27.1%	37.4%	13.2%	6.4%	100.0%

Table A.8: Emission and externality summary

Panel A: interconnection

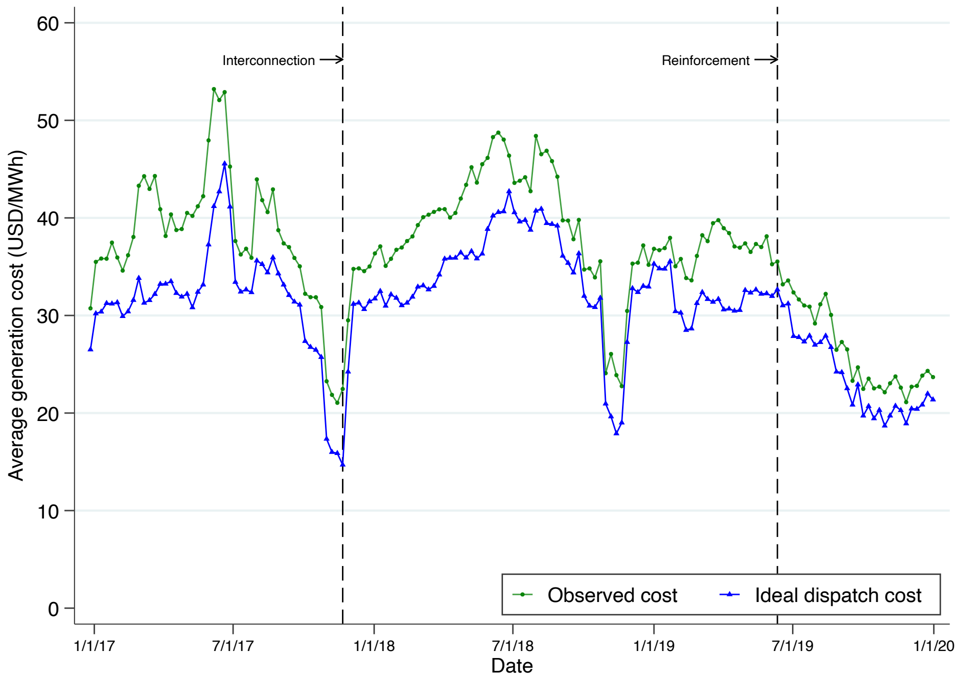
	Renewable	Hydro	Coal	Natural gas	Other thermal	Total
Generation ratio						
Interconnection only	11.6%	29.6%	36.1%	14.9%	7.8%	100.0%
No interconnection (static)	11.3%	29.7%	36.0%	15.2%	7.8%	100.0%
No interconnection (dynamic)	9.9%	29.7%	37.0%	15.5%	7.8%	100.0%
Generation level (GWh)						
Interconnection only	24.2	62.2	76.0	31.4	16.3	210.1
No interconnection (static)	23.7	62.2	75.5	32.0	16.4	209.8
No interconnection (dynamic)	20.7	62.2	77.8	32.7	16.4	209.8
Emission level (tons of CO2)						
Interconnection only	0.0	0.0	63082.7	10659.4	0.2	73742.3
No interconnection (static)	0.0	0.0	62683.1	10896.0	18.7	73597.8
No interconnection (dynamic)	0.0	0.0	64569.0	11130.9	23.6	75723.4
Non-carbon externality (1000 USD)						
Interconnection only	0.0	0.0	2584.1	62.7	0.0	2646.8
No interconnection (static)	0.0	0.0	2567.7	64.1	0.0	2631.8
No interconnection (dynamic)	0.0	0.0	2645.0	65.5	0.0	2710.5

Panel B: interconnection + reinforcement

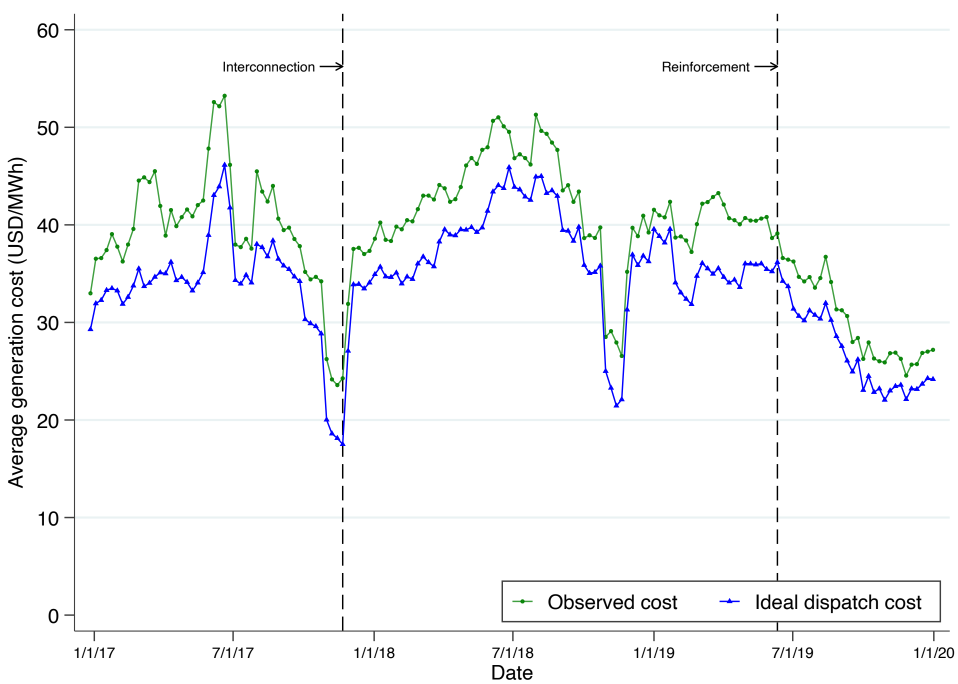
	Renewable	Hydro	Coal	Natural gas	Other thermal	Total
Generation ratio						
Actual scenario	16.0%	27.1%	37.4%	13.2%	6.4%	100.0%
No mkt integration (static)	14.3%	27.3%	36.0%	15.6%	6.7%	100.0%
No mkt integration (dynamic)	12.9%	27.3%	37.5%	15.6%	6.7%	100.0%
Generation level (GWh)						
Actual scenario	34.0	57.6	79.9	28.2	13.6	213.3
No mkt integration (static)	30.3	57.9	76.8	33.3	14.3	212.6
No mkt integration (dynamic)	27.3	57.9	79.8	33.3	14.3	212.6
Emission level (tons of CO2)						
Actual scenario	0.0	0.0	66332.0	9598.7	0.0	75930.7
No mkt integration (static)	0.0	0.0	63709.0	11326.8	2.9	75038.8
No mkt integration (dynamic)	0.0	0.0	66221.4	11336.9	2.9	77561.2
Non-carbon externality (1000 USD)						
Actual scenario	0.0	0.0	2717.2	56.5	0.0	2773.7
No mkt integration (static)	0.0	0.0	2609.8	66.6	0.0	2676.4
No mkt integration (dynamic)	0.0	0.0	2712.7	66.7	0.0	2779.4

Figure A.1: Observed Generation Cost and Ideal Dispatch Cost

Panel A: Hour 12

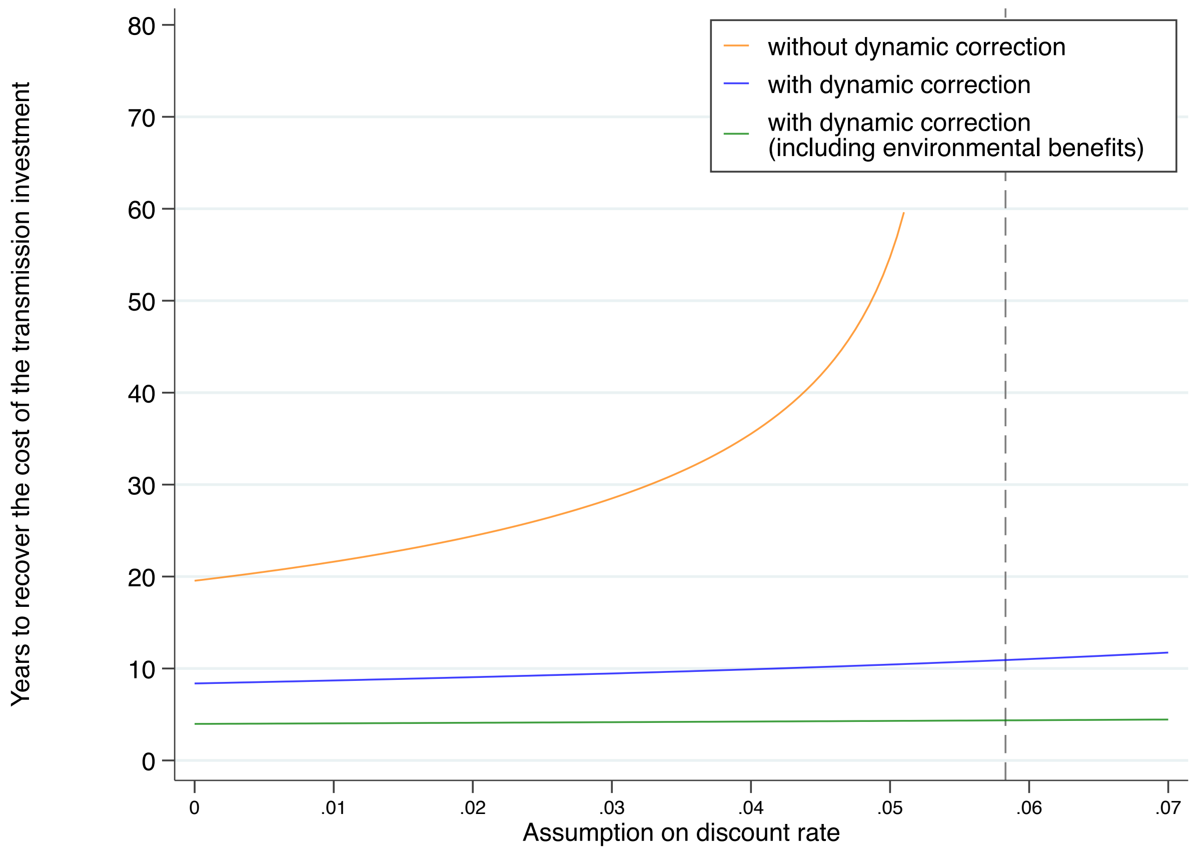


Panel B: All Hours



Note: This figure shows the observed system-level generation cost per MWh and the ideal dispatch cost (the minimum possible generation cost per MWh with full trade).

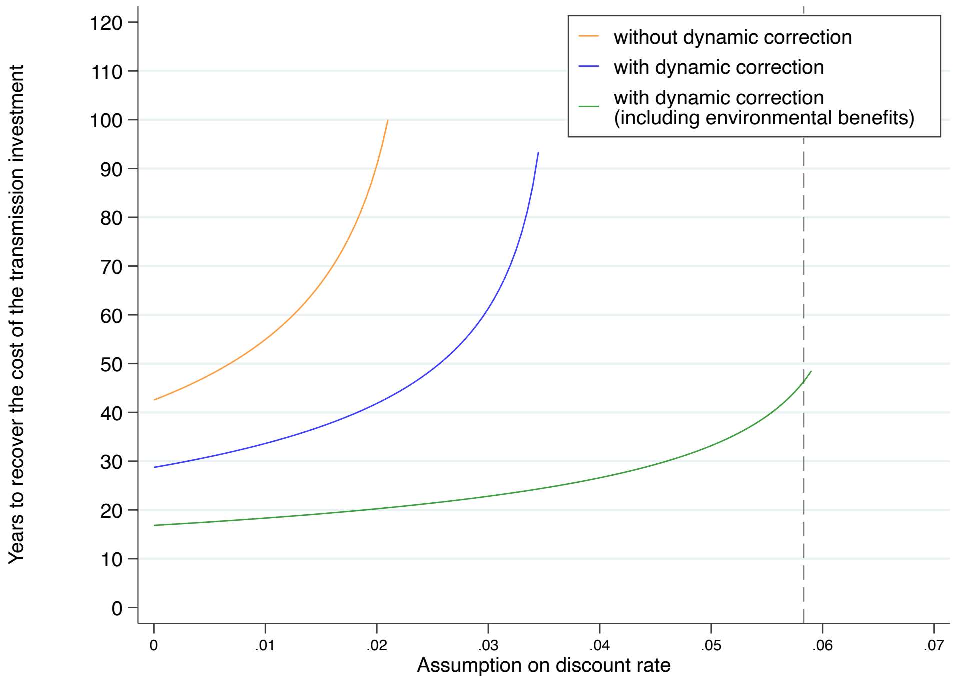
Figure A.2: Cost-Benefit Analysis of Transmission Investment: Interconnection only



Note: This figure shows the cost-benefit analysis of the interconnection, considering the case in which the interconnection was constructed but the reinforcement was not built.

Figure A.3: Alternative Approach to the Cost Benefit Analysis: Adding Solar Investment to the Cost

Panel A: interconnection + reinforcement



Panel B: interconnection

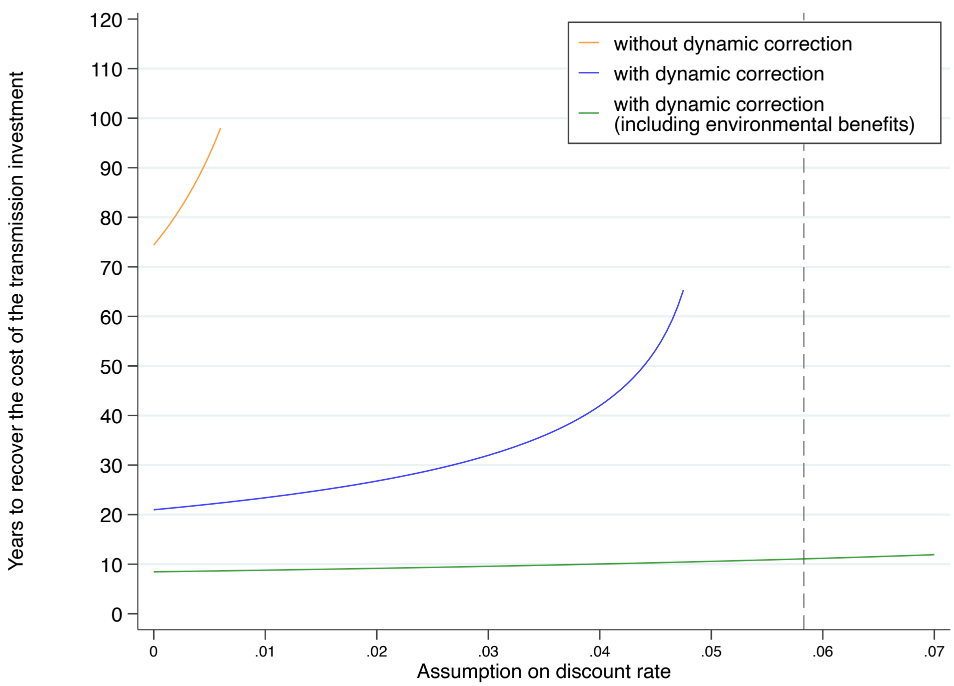
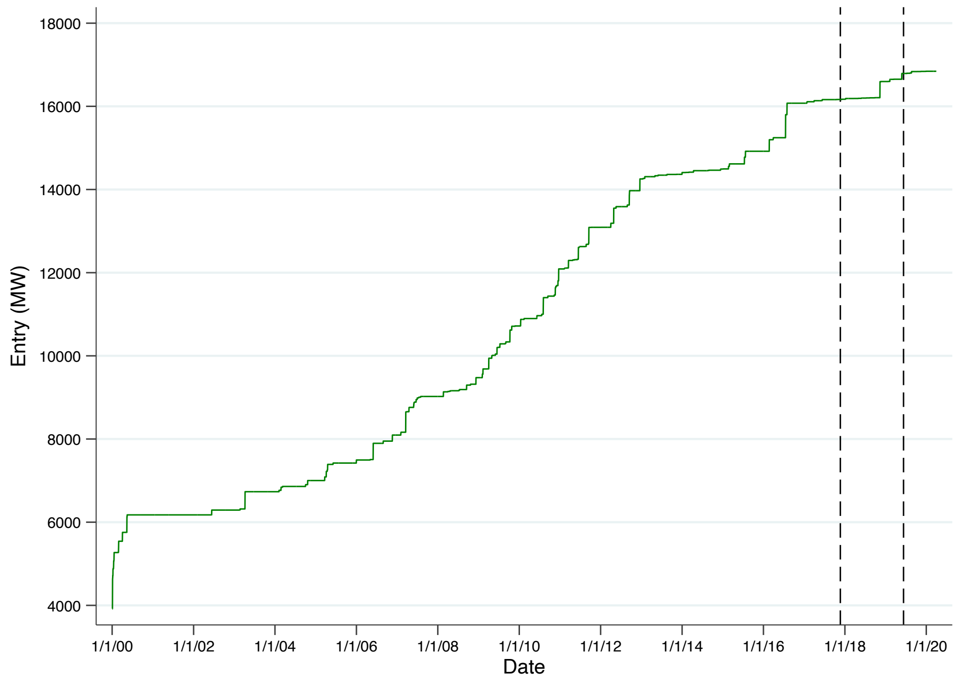
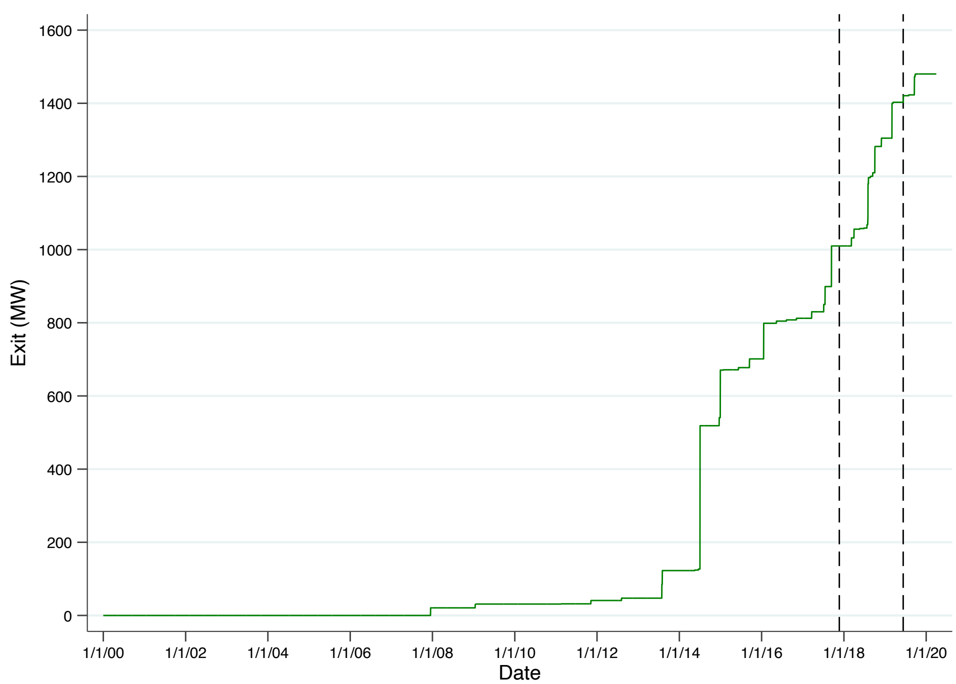


Figure A.4: Entry and Exist of Thermal Plants

Panel A: Entry

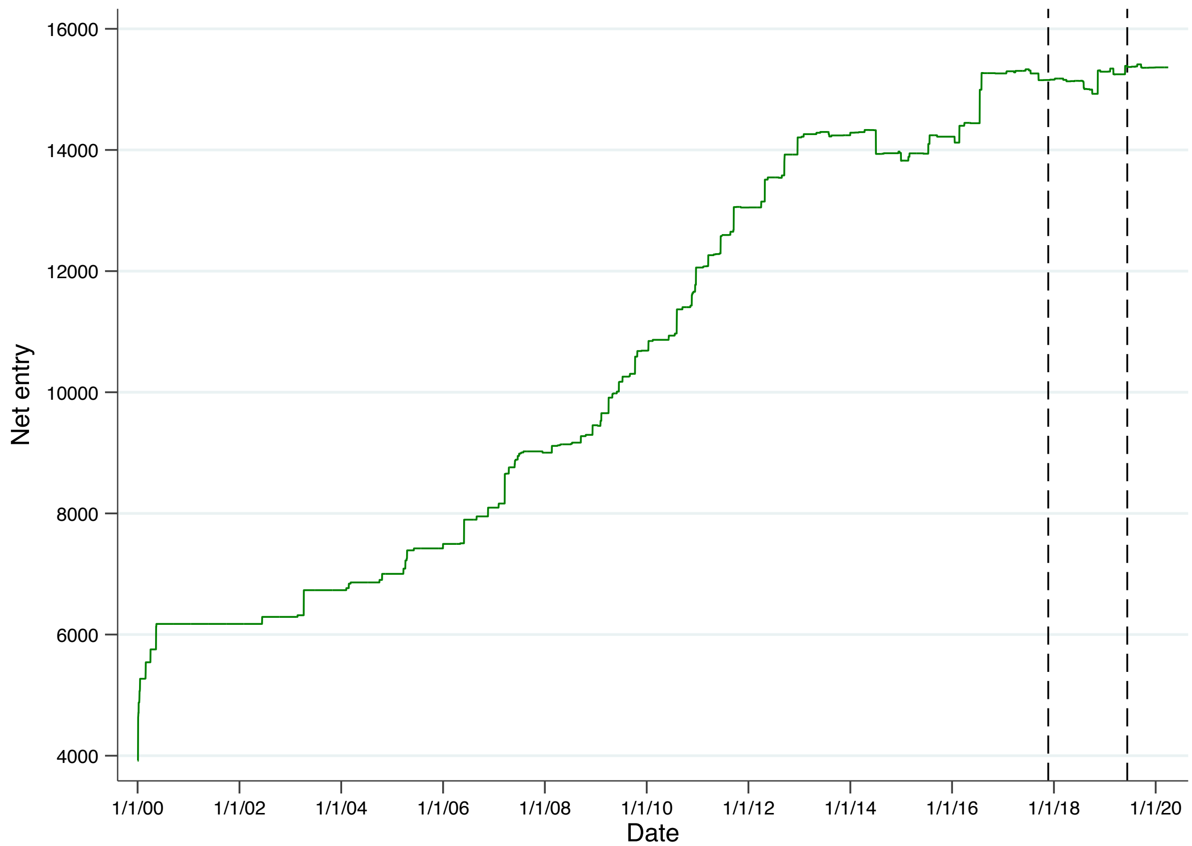


Panel B: Exit



Note: This figure shows the cumulative entry and exit of thermal plants. We use the first time of positive production to define unit-level entry and use unit-level capacity (MW) to show the cumulative entry in MW. For exit, we consider that a unit exited form the market if the unit does not produce in the last 6 months during our sample period. For these units, we use last time of positive production to define unit-level exit and use unit-level capacity (MW) to show the cumulative exit in MW.

Figure A.5: Net Entry (entry minus exit) of Thermal Plants



Note: This figure shows the cumulative net entry (entry minus exit) of thermal plants. See notes in Figure A.4.