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THE INVESTMENT EFFECTS OF MARKET INTEGRATION: EVIDENCE FROM RENEWABLE ENERGY EXPANSION IN CHILE

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We study the investment effects of market integration on renewable energy expansion. Our theory highlights that market integration not only improves allocative efficiency by gains from trade but also incentivizes new investment in renewable power plants. To test our theoretical predictions, we examine how recent grid expansions in the Chilean electricity market changed electricity production, wholesale prices, generation costs, and renewable investments. We then build a structural model of power plant entry to quantify the impact of market integration with and without the investment effects. We find that the market integration in Chile increased solar generation by around 180%, saved generation costs by 8%, and reduced carbon emissions by 5%. A substantial amount of renewable entry would not have occurred in the absence of market integration. Our findings suggest that ignoring these investment effects would substantially understate the benefits of market integration and its important role in expanding renewable energy.

KEYWORDS: Renewable energy, market integration, wholesale electricity markets, transmission expansion.

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 transporta-

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tion 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 fundamental challenge in expanding renewable energy because the existing network infrastructure (i.e., the transmission grid) was 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, is 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 and cannot be exported to other areas, electricity system operators have to curtail electricity generation from renewables to avoid system breakdowns, even though this means discarding zero marginal cost and emissions-free electricity. This curtailment indeed occurs in many electricity markets, and a growing number of markets are experiencing negative wholesale market prices when there is excess renewable supply.[2] Second, because the marginal cost of renewable electricity is near zero, local market prices in renewable-intensive regions tend to be low when the excess energy cannot be exported to demand centers. These two problems discourage new entry and investment in renewable power plants. Many countries consider these challenges as first-order policy questions. For example, the Biden administration in the United States explicitly included investment in transmission lines and renewable energy as a key part of the Infrastructure Investment and Jobs Act (117th Congress (2021)), which included approximately 1.75 trillion US dollars in spending.

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 impacts of market integration with and without investment effects. In the scenario holding investment fixed, 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 improves allocative efficiency. However, this conventional approach does not incorporate the potential investment effects of market integration. When producers can anticipate market integration, they have incentives to invest in new production capacity that will be profitable in the upcoming integrated market. This investment effect changes the supply curve of production, resulting in a different equilibrium. Our model shows that the investment effects of market integration can be substantial, and ignoring these effects 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)

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

[2]For example, California's wholesale market experienced negative prices 10% of the time in 2017 (California ISO (2018), Cicala (2021)). Wind power is often curtailed in electricity markets in Texas and Spain. The Japanese electricity market experienced large-scale curtailment of solar power in the Kyushu region, which has limited transmission connection to other parts of the country.

and Sistema Interconectado Central (SIC)—had been 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 the Atacama desert) are located far north from demand-centered regions (near Santiago, the capital city) and completely disconnected with another demand center (mining industry) near Antofagasta. To address this problem, the Chilean government completed a new interconnection between Atacama and Antofagasta in November 2017, and a reinforcement transmission line between Atacama and Santiago 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 costs, 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 event-study impacts of market integration on wholesale electricity prices, production, and cost. First, we show that the market integration resulted in price convergence across regions. Before the market integration, we observe large price differences between regions with high levels of solar production (e.g., Atacama) and demand centers (e.g., Santiago). 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 event-study impacts of market integration on electricity production and costs. Consistent with our theoretical prediction, we find that market integration provided gains from trade—lower-cost power plants, including renewables, increased their production and replaced production from higher-cost plants, decreasing the overall cost of electricity generation per megawatt hour.

Third, we examine how market integration affected new entry of renewable capacity. We find that a rapid growth in renewable capacity started right around the first *announcement* of market integration in 2014, which was 3 years before the completion of the interconnection in 2017. Despite the fact that the node prices in renewable-intensive regions became near zero before the interconnection, we observe continuing entries of renewable power plants in this period. This evidence suggests that renewable investors made their investment decisions based on the *anticipation* of market integration. This evidence also suggests that the event-study analysis, which cannot capture the potential impact of anticipatory investment in plant capacity, is likely to understate the impact of market integration, as our theory suggests.

We build a structural model of power plant entry to investigate the potential investment effects of market integration. In our investment 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 profits from subsequent years. A key element of 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 and examine the impact of market integration on solar entries, market prices, generation costs, and consumer surplus.

Our counterfactual simulations reveal several findings. First, the result that ignores the investment effect suggests that the market integration in Chile increased 10% of solar generation relative to the counterfactual case with no market integration. In the absence of market integration, the system operator would have had to curtail an excessive amount of solar power due to transmission constraints. Second, this number understates the impact on solar investment because a substantial amount of solar investment would have become unprofitable in the absence of market integration due to low market prices in solar-abundant regions. We simulate the market equilibrium to find the maximum level of solar capacity investment that could be positive in the net present value, using the discounted rate and duration of investment used by the Chilean government's public infrastructure projects. With this investment effect, our result suggests that the full impact of market integration on solar generation was a 178% increase in solar generation, as opposed to the 10% increase if we ignore the investment effect.

Our results indicate that both the grains from trade and investment effects of market integration are important factors in the evaluation of transmission investment. In our context, we find that the gains from trade itself resulted in 7% and 3% reductions in electricity generation cost per megawatt hour in hour 12 (a solar-intensive hour) and all hours, respectively. If we incorporate the investment effect, these reductions in generation cost are 18% and 8%. Our results also indicate that market integration plays key roles in allowing price convergence across regions.

We use our counterfactual simulation results to conduct the cost-benefit analysis of transmission investments. In particular, we discuss how the cost-benefit calculation can be changed with and without investment effects. We find that ignoring the investment effect of market integration substantially understates the benefit of transmission investments. Furthermore, reductions in environmental externalities provide an additional benefit of market integration. Our analysis suggests that the cost of transmission expansion can be recovered by 7.2 years with a 5.83% discount rate, and the internal rate of return is 19.7%.

Related Literature and our Contributions—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 analog to these hypothetical settings, which allows us to test predictions from these theoretical models. In addition, previous studies generally focus on immediate impacts and do not explicitly incorporate potential effects on the entry of new power plants. Our theory incorporates this investment effect and highlights that the investment impacts can be crucial to examine market integration.

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 in the US electricity markets. Our study is also related to research on the role of transmission lines in electricity markets. For example, Wolak (2015), Ryan (2021), and Burlig, Preonas, and Jha (2022) study the competitive and efficiency effects of transmission. Davis and Hausman (2016) examines how the impact of a sudden nuclear power plant closure on market efficiency interacts with transmission constraints. While our paper benefits from insights from this literature, our research question is different in three-folds. First, we study 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 isolate the effects of market integration from the impacts of dispatch mechanisms. Second, we focus on the role of market integration on renewable investment rather than the competitive impacts of transmission. Third, previous studies in this literature generally focus on allocative efficiency in a scenario in which the set of power plants is considered fixed. Our paper explicitly considers both of the immediate and investment impacts of market integration by incorporating power plant entries. Finally, our study shows that a commonly-used event study approach might understate the benefit of transmission lines, and we provide a structural method to include investment effects.

Third, our project relates to recent studies on the role of transmission expansion in renewable energy policy (Abrell and Rausch (2016), Dorsey-Palmateer (2020), Brown and Botterud (2021), Fell, Kaffine, and Novan (2021), LaRiviere and Lyu (2022), Yang (2022)). For example, Fell, Kaffine, and Novan (2021) finds 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 power 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 the impacts of market integration with investment effects is important to quantify the full benefit of transmission expansions. Second, in addition to nonmarket environmental benefits, we also evaluate the benefits of a variety of market outcomes in a wholesale electricity market, such as market prices and generation costs. We find that the economic benefits of market integration on these outcomes are substantial because renewable expansion can significantly lower the systemwide costs and prices of electricity when it is combined with transmission expansion. In our cost-benefit analysis, we show that incorporating the investment effect substantially changes the cost-benefit of transmission investments.[3]

Fourth, our paper relates to the literature computing optimal investment in solar power. A growing literature has examined household decisions with dynamic structural models at the household level in the context of residential rooftop solar installation (De Groote and Verboven (2019), Feger, Pavanini, and Radulescu (2022)). In these settings, households choose the optimal timing in which to invest in solar panels considering the option value of waiting for lower costs of solar versus missed opportunities in the form of higher subsidies. In residential settings, households only have one rooftop on which to install panels and, therefore, the optimal timing of investment is critical to each household. Our context is different because we study firms that build utility-scale solar plants in the Atacama desert and surrounding regions. These firms are able to build multiple large-scale solar plants at any point in time and do not have subsidies. Our data suggest that these firms can enter competitively, thus driving expected equilibrium profits to zero. Therefore, we model firms investing in the market as long as there are profitable opportunities, focusing on the aggregate equilibrium quantity of solar investment.

Finally, our study provides important policy implications for renewable energy policy around the world. The lack of market integration between renewable-intensive regions and demand centers has become a major obstacle to decarbonization in many countries, including the United States (Cicala (2021)). Chile is one of the very first countries that have tackled this problem by enhancing electricity market integration. Our empirical evidence from the Chilean electricity market highlights the importance of transmission projects in allowing investment into renewable energy, which is a crucial market force to accelerate decarbonization.

[3]Another related study is Rivera, Ruiz-Tagle, and Spiller (2021), which studies the effect of increased solar production on health outcomes in Chile, although this study's focus is not transmission expansion.

2. THEORETICAL FRAMEWORK

Our goal is to understand the benefits of integrating markets with and without investment effects, 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, A and B, which are operating in autarky. Region A has lower costs. Equilibrium prices in autarky are given by $p_A < p_B$. First, 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 (the triangle e_B, e_A, and e^*), which can be compared to the costs of building the line for a full cost-benefit evaluation.[4]

Second, we consider the benefits of market integration with investment effects. Imagine that region A is the one with the best available solar resources. In the absence of a

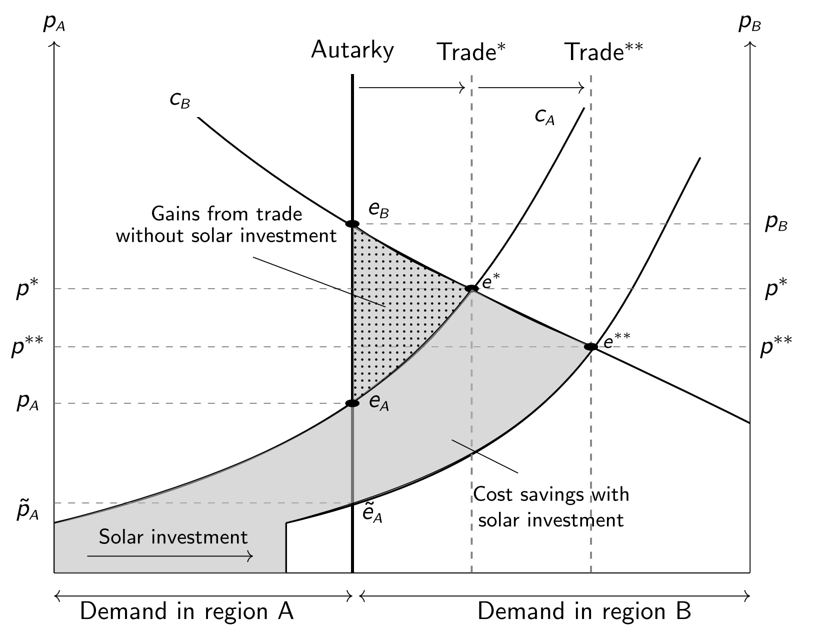


FIGURE 1.—Impacts of market integration with and without investment effects. *Note*: This figure summarizes theoretical predictions described in Section 2. The case without investment effects considers the impact of market integration, assuming that it does not affect the entry of solar plants. In contrast, the case with investment effects takes into account the impact on solar entry. Without investment effects, market integration moves the equilibrium to e^*, resulting in gains from trade equal to the triangle area e_B, e_A, and e^*. In the case with investment effects, market integration also induces entries of solar plants that have zero marginal cost. As a result, it shifts the cost curve in region A to the right. This equilibrium (e^{**}) generates additional cost savings on the entry of solar plants. We also show that when solar entry occurs in the anticipation of market integration, a commonly used event study design captures only a partial impact (the triangle area e_B, $\tilde{e}_A$, and e^{**}) rather than the full impact of market integration.

[4]Our theory model in this section focuses on a case of cost-based dispatch with no firm conduct because Chile uses the cost-based dispatch as we describe in Section 3.2. The model needs to be modified when firms' market conducts need to be incorporated.

transmission line between A and B, such resources might not be profitable, but they would be attractive if the two regions were interconnected. Once the two regions are interconnected, new investment enters the market in anticipation of the profitable environment. In Figure 1, we represent the equilibrium outcome after renewable plants are built in region A. Under full trade, the investment equilibrium would be e^{**} with the equilibrium price p^{**}. The cost savings from this new equilibrium are described by the whole shaded area. To get at the full investment 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, for example, using an event-study like the *ceteris paribus* comparison. From Figure 1, in the absence of solar investment, the benefits from the expansion should identify the full 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 investment 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 in a commonly-used "event study design" could lead to the conclusion that the event-study gains from trade equal the larger shaded triangle (the triangle e_B, $\tilde{e}_A$, and e^{**}). This calculation will not only understate the gross cost savings, but it would also fail to account for the fact that solar investments would not have been profitable during the "before" period alone.

More generally, we expect an event-study 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 investment impacts in the event window. When it comes to price differences, the event-study approach will overestimate the overall impacts of the transmission line on price convergence in the presence of anticipated investments as long as $p_A < p_B$. Early investments will increase the price difference, which will tend to converge after the grid is expanded. 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 $r = \{A, B\}$ with demands $D_A \leq D_B$ and marginal cost functions $C_A(q_A) = \beta_A q_A$ and $C_B(q_B) = \beta_B q_B$, where q_A and q_B represent nonsolar production in each region. For simplicity, consider the case in which $\beta_A \leq \beta_B$ so that under autarky $p_A \leq p_B$, 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:

$$p_A = \beta_A D_A, \qquad q_A = D_A, \qquad p_B = \beta_B D_B, \qquad q_B = D_B.$$

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

$$p^* = \frac{\beta_A \beta_B}{\beta_A + \beta_B} D, \qquad q_A = \frac{\beta_B}{\beta_A + \beta_B} D, \qquad q_B = \frac{\beta_A}{\beta_A + \beta_B} D.$$

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 region A.[5] For simplicity, assume $p_A < c < p^*$, so that investment only occurs under market integration. We also assume that the entry of solar follows a zero-profit condition. In this new environment, the equilibrium solar production becomes

$$q^{\text{solar}} = D - \frac{\beta_A + \beta_B}{\beta_A \beta_B} c.$$

Intuitively, solar covers any demand not produced by the regions at price $p^{**} = c$, which becomes the equilibrium price under full trade.[6]

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

$$p_A = \left(1 + \frac{\beta_A}{\beta_B}\right) c - \beta_A D_B, \qquad q_A = \frac{\beta_A + \beta_B}{\beta_A \beta_B} c - D_B, \qquad p_B = \beta_B D_B, \qquad q_B = D_B.$$

The price and nonsolar production in region A will be lower in this new equilibrium with anticipation, while prices and production in region B remain at the same level in autarky.

Armed with this basic model, we show the following observations.[7]

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

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

Visually, it is clear that gross cost savings are largest when the full shaded area is considered.[8] In the presence of delayed investments, gains from trade realized around the event window are only equal to the gains without investment, which are by construction smaller. If an 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 region A.

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 straightforward to see that with investment anticipation, prices before market integration will tend to be lower than without anticipation because solar production depresses the market equilibrium price. Therefore, price reductions will be less salient if solar investment has already occurred. In the presence of investment delays, the key is to show

[5]Solar production involves mostly fixed costs. The cost c is intended to capture the strike price at which solar panels are profitable.

[6]We assume that c is such that solar investment is at an interior solution, that is, $q^{\text{solar}} \geq 0$, as implied by $p_A < c < p^*$.

[7]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.

[8]See the Appendix in the Online Supplementary Material (Gonzales, Ito, and Reguant (2023)) for mathematical proofs of all results.

that price reductions are larger in the investment equilibrium than in the one with no solar investment. This is again due to the depressing effects on prices from solar entry, which only occur in the case with investment effects.

OBSERVATION 3: *In the presence of investment anticipation or delay, reductions in* ***regional price differences*** (*price convergence*) *around the event window 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 region A are depressed in the presence of anticipation of investments, as shown in Figure 1 when comparing p_A to $\tilde{p}_A$. Therefore, the price gap in prices $p_B - \tilde{p}_A$ is overstated. If the 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.

In our empirical analysis below, we consider these insights and provide empirical quantification to the theoretical predictions described in this section.

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 left panel), the electric power grid in Chile was organized into 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.

In November 2017, these two systems were connected for the first time, with a double circuit 500 kV transmission line with a firm capacity of 1500 MW. As we show in the middle panel of Figure 2, the interconnection connected the Antofagasta region in SING and the Atacama region in SIC. The integrated new system—Sistema Electrico Nacional (SEN)—consists of over 99% of the installed capacity for the country.[9]

In June 2019, this interconnection was extended by another double circuit 500 kV transmission line (the right panel of Figure 2) to reinforce the connection between Atacama and Santiago. In this paper, we use "interconnection" to refer to the interconnection line (Antogagasta–Atacama) built in 2017 and "reinforcement" to refer to the reinforcement line (Atacama–Santiago) built in June 2019. As we show in our analysis below, both of interconnection and reinforcement played key roles in integrating the Chilean electricity market.

[9]The remaining 1% is served by two other isolated systems in the south of SIC outside the map in Figure 2.

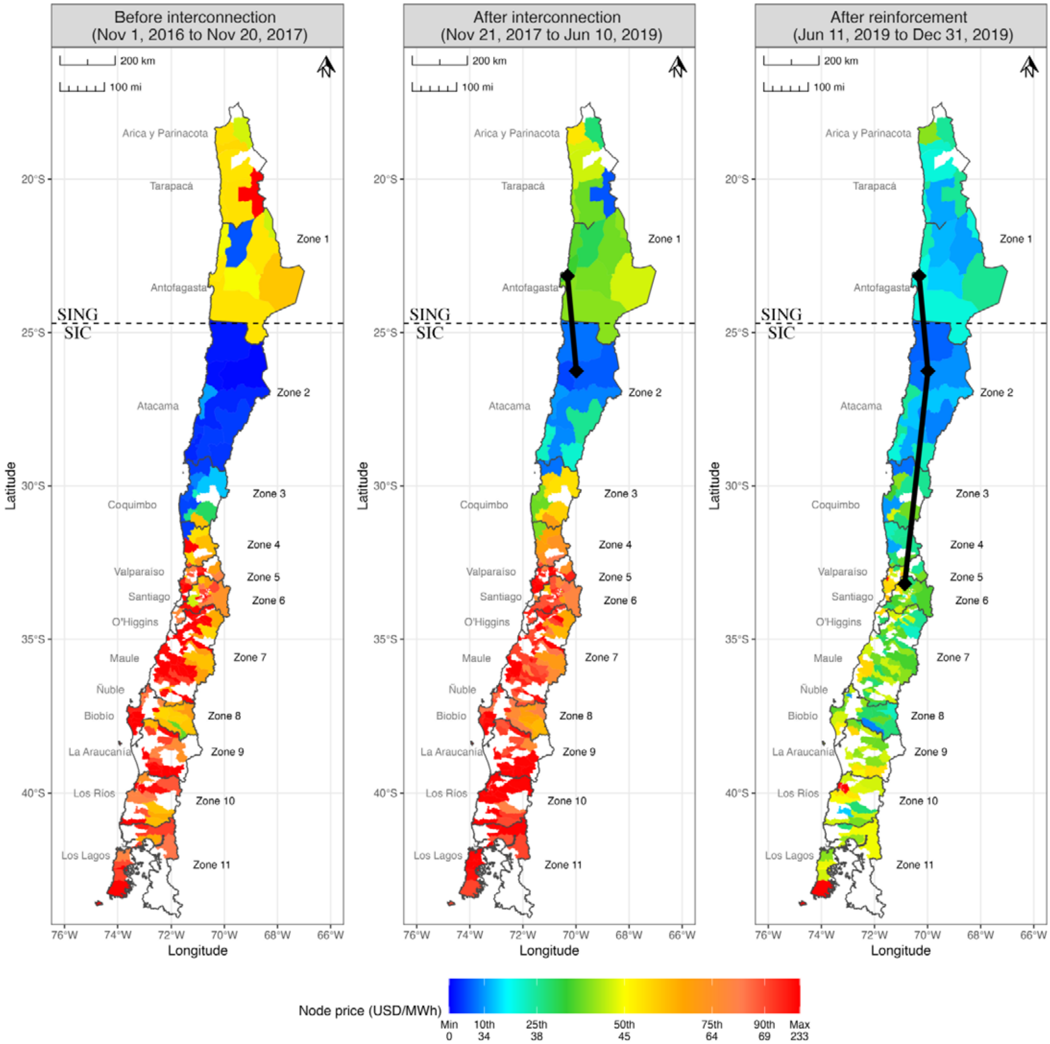


FIGURE 2.—Market integration and spatial variation in electricity prices. *Note*: These heat maps examine spatial heterogeneity in wholesale electricity prices. We calculate the commune-level average node prices, weighted by the hourly generation at the node level, and make heat maps for three time periods: (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. We also show the boundaries of zones defined in Section 5. Zones 1–11 include the following regions (a more detailed mapping is provided in Figure A.2). Zone 1: Arica y Parinacota, Tarapacá, Antofagasta; Zone 2: Atacama, and one commune in Antofagasta; Zone 3: parts of Coquimbo; Zone 4: parts of Coquimbo, parts of Valparaíso; Zone 5: parts of Valparaíso; Zone 6: Santiago, parts of O'Higgins; Zone 7: parts of O'Higgins, Maule, Ñuble; Zone 8: Biobío; Zone 9: La Araucanía; Zone 10: Los Ríos, parts of Los Lagos; Zone 11: parts of Los Lagos.

A major policy objective of this integration was to connect solar-abundant regions to electricity demand centers. Atacama is a solar-abundant region with relatively low electricity demand. Antofagasta is one of the demand centers for its mining industry, and Santiago is the largest demand center for its commercial, industrial, and residential electricity demand. There are two ways to interpret Chile's market integration in the context of the theoretical framework presented in Figure 1. Atacama can be considered to be region A (the solar-abundant region), and the interconnection and reinforcement connected it to region B (Antofagasta and Santiago, two demand centers) sequentially. Note that Antofagasta is also abundant with solar resources, although it is less so than Atacama. Therefore, another interpretation is that the interconnection and reinforcement—combined together—connected the solar-rich regions in the north (Antofagasta and Atacama) with Santiago, the largest demand center in the country.

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

3.2. *Cost-Based Dispatch and Pricing in the 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 decides 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 disaggregated 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 the advantage of reducing the risk of systemwide 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 in Appendix C, we do not find evidence of large firms exercising market power in our sample period.[10]

To hedge spot market risk, generators can also sign long-term contracts with customers.[11] Customers with installed demand capacity over 500 kW can have bilateral contracts with generators. Other customers are called "regulated customers" because they are served by local distribution companies with regulated retail prices. These customers cannot have direct contract with generators. Instead, the long-term contracts are auctioned in a centralized auction between local distribution companies and generators. Generators with long-term contracts can either generate electricity or purchase it from the spot market. Thus, these long-term contracts are equivalent to financial positions and their price should be reflective of the market price expectations.

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.[12] We use several data sets for our empirical analysis.

Hourly and Daily 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. For power plants in SIC regions, we use unit-level costs for three segments of the day: block 1 (midnight to 8 a.m.), block 2 (8 a.m. to 6 p.m.), and block 3 (6 p.m. to midnight). For power plants in SING regions, we use unit-level daily cost data. We use this data from 2014 through 2019.

Hourly Demand at the Node Level: Our data cover 2017 through 2019.

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

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

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

The summary statistics in Table I 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). Second, hourly system demand does not vary much across hours as it is suggested by the hourly generation at noon and

[10]The cost-based market in Chile makes our analysis more parsimonious as market power is less of an issue. At the same time, the analysis based on the Chilean market abstracts from an additional potential benefit of market integration that comes from increased competition. If such an effect exists, the full benefit of market integration can be larger in a market with bid-based dispatch compared to a market with cost-based dispatch.

[11]Long-term contracts are optional to generators. They can participate in the spot market without long-term contracts. Bustos-Salvagno (2015) provides a detailed description of the long-run contracts in the Chilean electricity market.

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

TABLE I

SUMMARY STATISTICS.

	Pre-Interconnection (Nov. 2016–Nov. 2017)		Post-Interconnection (Nov. 2017–Dec. 2019)
	SIC	SING	SEN
Hourly total generation at noon (MWh)	6851 (645)	2135 (186)	9349 (647)
Hourly total generation at midnight (MWh)	5900 (316)	2241 (195)	8482 (351)
Node price at noon (USD/MWh)	54.46 (35.58)	45.14 (16.95)	52.16 (25.01)
Node price at midnight (USD/MWh)	52.06 (24.9)	71.66 (35.26)	54.82 (20.94)
Variable cost: Thermal (USD/MWh)	44.67 (17.28)	42.94 (11.12)	43.73 (15.08)
Installed capacity (*MW*)			
Hydro	6225	16	6304
Solar	1315	603	2500
Thermal	6131	3832	10,385
Wind	1144	194	2009

Note: This table shows the summary statistics of our data. Installed capacity is defined as the 99th percentile of hourly generation.

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, Bushnell, and Wolak (2002), Wolak (2011), Ito and Reguant (2016), Ito, Ida, and Tanaka (2018, 2021)). 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.

4. DESCRIPTIVE ANALYSIS OF MARKET INTEGRATION

In this section, we use detailed data on hourly price, cost, electricity generation, and plant entries to provide descriptive analysis of market integration. An advantage of this analysis is that we can explore empirical evidence with minimal reliance on modeling assumptions. A key limitation is that descriptive analysis by itself is not sufficient to examine the full impact of market integration with investment effects. We will investigate this point in Section 5.

4.1. *Impacts of Market Integration on Wholesale Electricity Prices*

One of the theoretical predictions in Section 2 is that market integration could result in convergence in wholesale electricity prices between regions. We test this prediction in Figure 2. As mentioned in Section 3.3, we have data on the hourly wholesale electricity prices at the node level. Using these data, we calculate the commune-level average prices, weighted by the hourly generation at the node level, and make heat maps for three periods: (1) before the interconnection, (2) after the interconnection and before the reinforcement, and (3) after the reinforcement. The heat maps show the average node prices at noon, which tend to be one of the most congested hours in the transmission network in Chile because of solar generation.

Prior to the interconnection (the left heat map), there was a steep price difference between Atacama and other regions. This is because zero-marginal-cost solar generation in Atacama depressed the market price toward zero and it was not possible to export

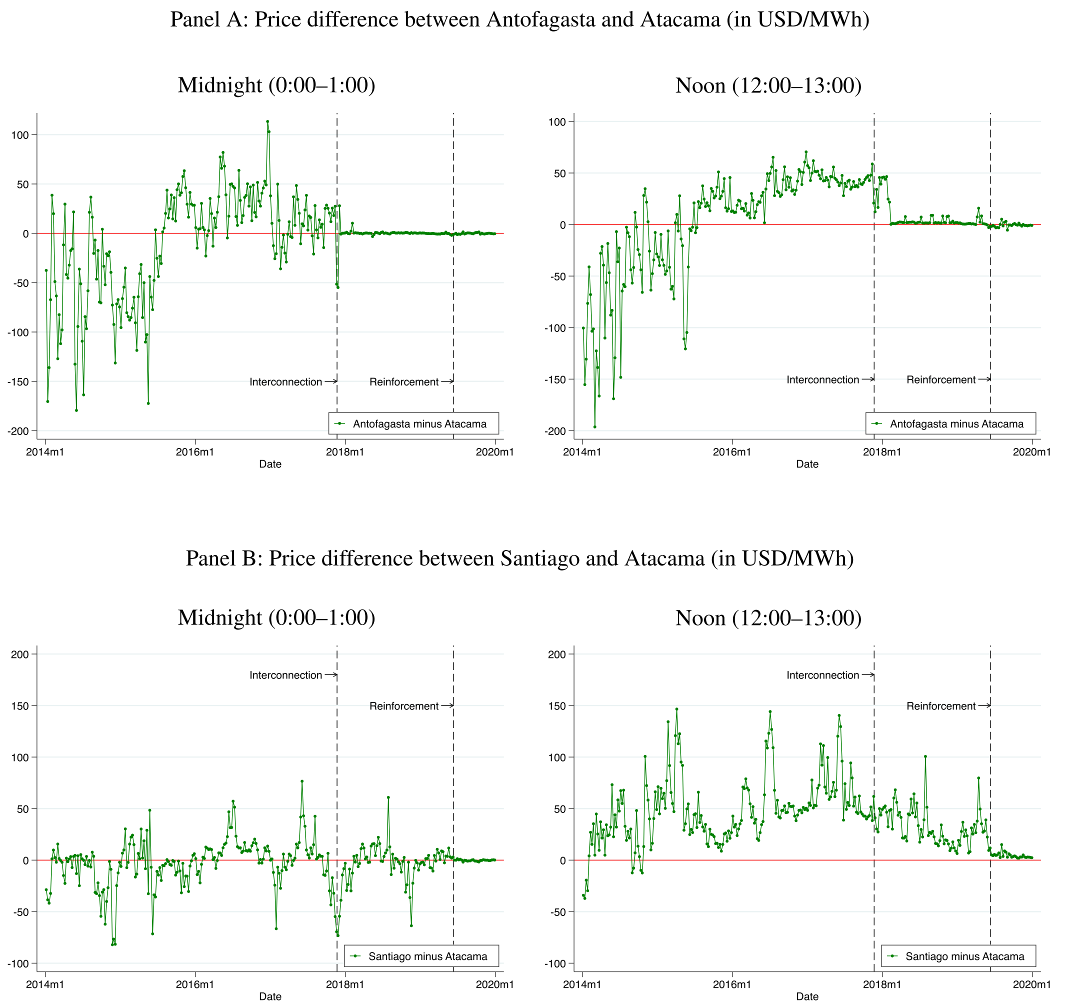


FIGURE 3.—Impacts of market integration on price convergence. Panel A: Price difference between Antofagasta and Atacama (in USD/MWh). *Note*: Panel A shows the price difference between Antofagasta and Atacama (the two end points of the interconnection), and Panel B shows the price difference between Santiago and Atacama (the two end points of the reinforcement). For each week, we calculate the weekly averages of hourly prices in each region. We then take the difference between these weekly averages and plot them over time. We use prices in Kapatur (a node in Antofagasta region), Cardones (a node in Atacama region), and Polpaico (a node in Santiago region) to calculate the price differences. These are the nodes nearest to each end point of the interconnection and reinforcement.

this excess solar production to other regions—there was no interconnection to the north (Antofagasta) and not enough transmission capacity to the south (Santiago).

The interconnection (the middle heat map) made it possible for low-cost solar power to be exported to the north, which lowered the price difference between Atacama and Antofagasta. However, the interconnection by itself had a limited impact on the price difference between Atacama and Santiago. The right heat map shows that a nationwide price convergence was achieved only after the opening of the reinforcement line in 2019.

In Figure 3, we examine the price convergence using time-series data. Panel A shows the price difference between Antofagasta and Atacama (the two end points of the interconnection), and Panel B shows the price difference between Santiago and Atacama (the two end points of the reinforcement). For each week, we calculate the weekly averages of hourly prices in each region. We then take the difference between these weekly averages and plot them over time.[13]

Panel A shows that there was large volatility in the price difference between Antofagasta and Atacama before the interconnection. Because these two regions were fully separated markets at this time, differences in demand or supply in each region could make the price different between the two markets. After the interconnection, the price difference converged to zero in nearly all weeks for midnight and most weeks for noon.

Panel B suggests that the interconnection slightly reduced the price difference between Santiago and Atacama, but it was not enough to get the price convergence. This is because the transmission capacity between Santiago and Atacama had not been enough between these regions until the reinforcement was opened in 2019. After the reinforcement, the price difference converged to zero in nearly all weeks for midnight and most weeks for noon.

Our theory (Observation 3 in Section 2) implies that the price convergence observed at the time of market integration (i.e., the change in the regional price difference before and after the market integration) could overstate the price convergence effect of market integration if the solar investments occurred in anticipation of the grid expansions. That is, the price convergence observed in Figure 3 may reflect $p_B - \tilde{p}_A$ rather than $p_B - p_A$ in Figure 1. We investigate this investment effect in Section 5.

4.2. *Impacts of Market Integration on Generation Costs*

Another theoretical prediction in Section 2 is that grid expansion could bring a textbook example of gains from trade. With market integration, the system operator can dispatch power plants in a way that minimizes total generation cost in all regions as opposed to minimizing each region's cost separately. We predict that the interconnection and reinforcement made lower-cost power plants produce more and higher-cost plants produce less, resulting in reductions in nationwide generation cost per MWh.

One way to measure this efficiency gain is to examine how generation cost per MWh changed before and after the grid expansions. However, the observed change in generation 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 challenge, we use insights from Cicala (2022) and take advantage of the fact that we can compute the "nationwide merit-order cost." This nationwide merit-order cost is the least possible dispatch

[13]We use prices in Kapatur (a node in Antofagasta region), Cardones (a node in Atacama region), and Polpaico (a node in Santiago region) to calculate the price differences. These are the nodes nearest to each end point of the interconnection and reinforcement.

cost per MWh that can be obtained in the absence of trade constraints in the Chilean electricity markets and can be a useful control that takes into account nonlinearities in the costs of producing electricity as a function of commodity prices (coal and gas) and hydro availability.

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, assuming there is no trade constraint. We use c_t^* to denote this nationwide merit-order cost (USD/MWh) at time t and c_t to denote the observed generation cost per MWh at the national level.[14] Using c_t^* as one of the control variables in X_t, we estimate the following equation by the OLS:

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

where $I_t = 1$ after the interconnection (November 21, 2017), $R_t = 1$ after the reinforcement (June 11, 2019), X_t is a vector of control variables that includes the nationwide merit-order cost c_t^*, θ_m is the month fixed effects to control for seasonality, and u_t is the error term. We calculate heteroskedasticity- and autocorrelation-consistent standard errors.[15]

Table II shows the results. A key advantage of this approach is that many time-variant factors, such as input prices, can be flexibly controlled by c_t^* and, therefore, results are robust to the inclusion of additional controls. Columns 4 and 8—the specifications that include all control variables—imply that the interconnection and reinforcement reduced the generation cost by 2.42 and 0.96 USD/MWh for hour 12 and by 2.07 and 0.62 USD/MWh for all hours.

Our theory (Observation 1 in Section 2) suggests that the cost reduction estimated by comparing before and after the market integration (i.e., our results in Table II) could understate the full cost saving if the solar investments occurred in anticipation of the grid expansions.[16] We investigate the anticipatory investment in Section 4.3 and incorporate such investment effects in Section 5.

4.3. *Impacts of Market Integration on Renewable Expansion*

Observations 1, 2, and 3 in our theory imply that the before-and-after analysis may not capture the full impacts of market integration if the entry of power plants occurs in antic-

[14] Cicala (2022) calculates the merit-order cost within each power control area, whereas our nationwide merit-order cost is defined as the least dispatch cost at the national level, as opposed to SING only or SIC only. In addition, an alternative control variable is the minimum dispatch cost in the absence of market integration (i.e., the least possible generation cost that can be obtained in the absence of market integration). We use this approach in Table A.V and find that results are similar to Table II.

[15] There are two approaches to using c_t^* as a control variable. One approach is to define the out-of-merit cost $c_t - c_t^*$, which shows how much the observed cost deviates from the least possible dispatch cost, and use it as a dependent variable. In this way, we could test how market integration changed the deviation between c_t and c_t^*. Another approach is to use c_t as a dependent variable and c_t^* as a control variable. We find that both approaches produce essentially identical results because empirically the coefficient for c_t^* is close to one in the second approach. This is because c_t and c_t^* generally move in a parallel way (Figure A.1). We show the result of the second approach in this section and include the result of the first approach in the Appendix (Table A.IV).

[16] The event study model, such as equation (1), identifies the effect of an event by comparing outcomes before and after the event, assuming that the event affects outcomes in the post-event period but does not affect pre-period outcomes. In our context, if the event induces anticipatory investments, it could lower the generation cost in the pre-event period, which could result in the underestimation of the event's impact on cost savings.

TABLE II

EVENT STUDY ANALYSIS OF GENERATION COST (WITHOUT INVESTMENT EFFECTS).

	Hour 12				All Hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	−2.75	−2.48	−2.51	−2.42	−2.16	−2.15	−2.15	−2.07
	(0.20)	(0.27)	(0.27)	(0.26)	(0.15)	(0.17)	(0.17)	(0.17)
1(After the reinforcement)	−1.20	−1.13	−1.32	−0.96	−1.09	−0.63	−0.64	−0.62
	(0.20)	(0.55)	(0.58)	(0.58)	(0.14)	(0.35)	(0.37)	(0.37)
Nationwide merit-order cost	1.08	1.10	1.10	1.12	1.01	1.02	1.02	1.03
	(0.02)	(0.03)	(0.02)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		−0.03	−0.03	−0.03		−0.01	−0.01	−0.01
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			−9.92	−10.27			−0.37	−0.55
			(4.32)	(4.33)			(3.12)	(3.10)
Hydro availability				0.43				0.00
				(0.14)				(0.00)
Scheduled demand (GWh)				−0.51				−0.01
				(0.13)				(0.00)
Sum of effects	−3.95	−3.61	−3.83	−3.38	−3.24	−2.78	−2.78	−2.68
Mean of dependent variable	35.44	35.44	35.44	35.44	38.63	38.63	38.63	38.63
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.92	0.94	0.94	0.94	0.95	0.97	0.97	0.97

Note: This table shows the results of the regression described in equation (1). The dependent variable is the observed hourly generation cost per MWh. We report heteroskedasticity- and autocorrelation-consistent standard errors in parentheses. The sample period is 2017–2019.

ipation of market integration.[17] This is particularly relevant to electricity grid expansions because the announcement and subsequent construction of transmission lines generally start long ahead of the opening of the lines.

To investigate the importance of this point in our empirical context, we examine the entry of solar plants in Figure 4. The red-connected line shows the cumulative installed capacity for solar plants in Atacama. The green solid line shows the average price at noon, and the green dashed line shows the average price at midnight.[18] Before 2014, there were nearly no solar plants in this region, and the prices were similar between noon and midnight. When more solar plants started to enter, the prices at noon started to decline and reached near zero in 2015. 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 constraints. The transmission constraint was relaxed when the interconnection was opened in 2017. The interconnection made the price at noon get back to positive levels and shrunk the difference in prices between

[17]A before-and-after analysis will also produce biased results if entry is delayed. We focus here on anticipation because it appears to be clearly present in our application.

[18]We calculate the weighted average node prices in this figure using plant-level daily solar generation as weight.

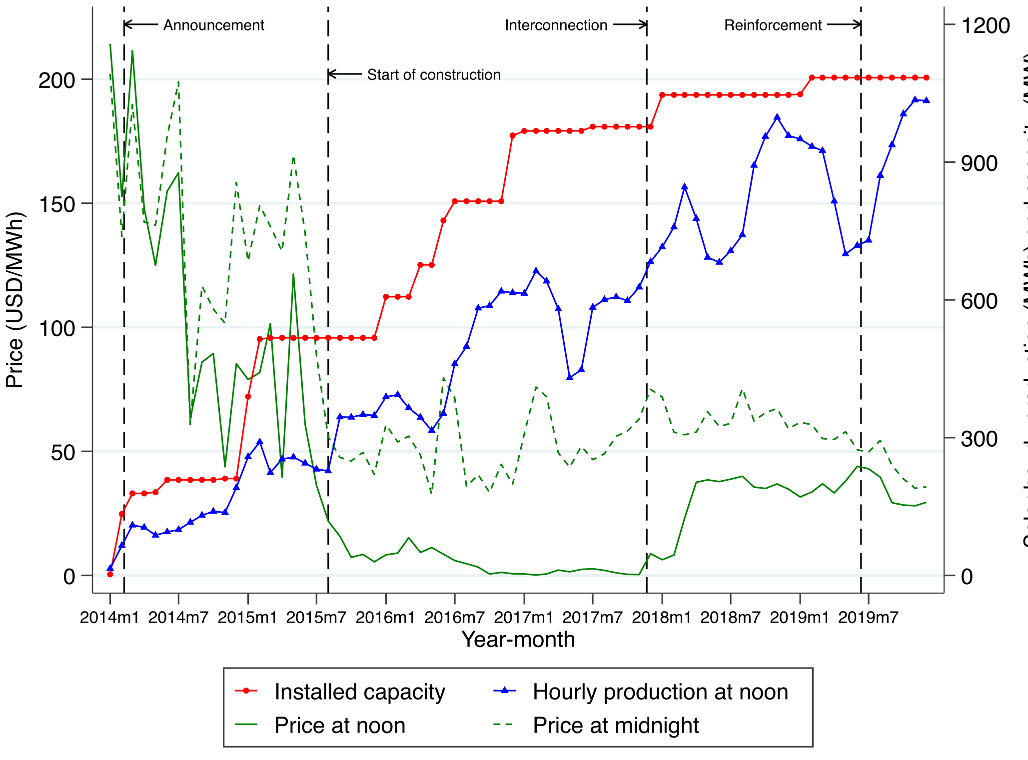


FIGURE 4.—Impacts of market integration on solar expansion. *Note*: This figure shows the cumulative installed capacity of solar plants, average hourly generation for each month, and node prices for these plants at noon and midnight in Atacama (zone 2). We calculate the weighted average node prices in this figure using plant-level daily solar generation as weight. As more solar enters around 2014–2015, the node price at noon began to decline and reached near zero around 2016. Despite the near-zero market price, solar entry continued, which suggests that this investment was considered to be profitable in the long run with the anticipation of market integration in 2017 and 2019. The "announcement" line shows February 2014, when the Chilean government passed a law that approved the construction of interconnection between SING and SIC. The actual contraction process started in August 2015.

noon and midnight. Furthermore, the reinforcement in 2019 further narrowed this price difference.[19]

The evolution of solar entries indicates that investors were likely to make investment decisions in anticipation of market integration. Between mid-2015 and mid-2017, the price in Atacama had been near zero. However, the solar entries had a steady increase in this period. This investment decision does not make sense without the anticipation that the grid expansions were going to alleviate transmission congestion and increase local prices.

There are several reasons why the anticipatory investment occurred. First, as we explained in Section 3.1, the relevant law was passed in 2014, and the construction of the interconnection line started in 2015, 2 years before the interconnection was opened. There-

[19]In Figure A.10 in the Appendix, we also show that in addition to the price at noon, the solar-relevant prices can be also analyzed by the weighted average prices weighted by solar potential. We find that this weighted price is nearly identical to the price at noon. In that figure, we also show that the declining prices in 2014–2015 were largely due to the declines in natural gas price.

fore, market participants had publicly available information about the upcoming market integration. Second, uncertainty in obtaining permits and competing constructions was likely to be another reason to rush firms into the anticipatory investment. Third, the fixed-price power purchase agreements were likely to make the anticipatory investment financially possible. Many solar plants in Chile were built with long-run fixed-price contracts. Because the information about the market integration was publicly available, the long-run contract prices, which were determined by a centralized auction for the regulated market and by bilateral agreements for the unregulated market, were likely to reflect the expected long-run local prices. If this is the case, solar plants were able to receive nonzero prices even during the pre-interconnection period.[20]

These findings from Figure 4 suggest that incorporating the investment effects of market integration is important to understand the value of the transmission expansion. In addition, the evidence of the anticipatory investment suggests that the before-and-after analysis presented in Sections 4.1 and 4.2 may not capture the full impact of market integration. In the next section, we address this question by developing a structural model of market integration.[21]

5. A STRUCTURAL MODEL OF MARKET INTEGRATION

In this section, we build a structural model of solar plant entry to investigate the impacts of market integration with and without investment effects. The model is composed of two parts. First, a short-run economic dispatch model is used to clear the market every week to determine power plant dispatch for each hour (Section 5.1). We take advantage of the fact that many relevant variables, such as hourly demand and daily cost at the power plant unit level, are observable in our data and that Chile's simple geography allows us to build a tractable trade model built into the dispatch model.

The second part of the model is about solar investors' investment decisions. We describe our investment model Section 5.2 and use this model, the dispatch model, and our data to solve for the equilibrium entry of solar plants. We then use this model to simulate the impacts of the transmission expansion project in Section 5.3.

5.1. *Dispatch Model*

The system operator in Chile uses the cost-based dispatch described in Section 3.2. The operator's objective is to dispatch power plants by minimizing the total generation cost given demand and transmission constraints. As a result of the optimization, the production decisions of each plant and hourly local market prices will be determined. We model

[20]A subset of the power purchase agreements for the regulated customers (i.e., customers with less than 500 kW) are publicly available, and we show time-series variation in Figure A.11. In this data, we confirmed that the average contracted price for solar plants was \$78 in the 2015 auction and \$52 in the 2016 auction. This suggests that solar plants were indeed able to obtain nonzero prices even before the interconnection. Unfortunately, the publicly-available data include only a small subset of the long-run contracts and, therefore, we mainly use the spot market data for our empirical analysis.

[21]We focus on solar investment, as this seems to be the largest margin of adjustment. However, other power plants could also endogenously respond to solar investment and the transmission expansion. In Figure A.9, we examine the entry and potential exit of thermal plants. We find that entry of thermal plants slowed down around 2014–2015 relative to total generation growth, which is consistent with their expected long-run profitability going down. We also find suggestive evidence on potential exits of thermal plants in response to the market integration, although correctly identifying the exit of power plants is challenging in electricity markets, as we describe in Appendix D.

that the operator finds the optimal dispatch for each hour t to minimize the weekly total generation cost.[22]

Mathematically, we solve the following constrained optimization problem for each week:

$$\begin{aligned}
\min_{\mathbf{q},\mathbf{imp},\mathbf{exp}} \quad & \sum_{z,t,j} C_{ztj}(q_{ztj}), \\
\text{s.t.} \quad & \sum_j q_{ztj} + \sum_l \big((1-\delta_1)\,\mathrm{imp}_{lzt} - \mathrm{exp}_{lzt}\big) \geq \frac{D_{zt}}{1-\delta_2}, \quad \forall z, t, \\
& 0 \leq \mathrm{imp}_{lzt} \leq f_{lz}, \qquad 0 \leq \mathrm{exp}_{lzt} \leq f_{lz}, \quad \forall l, z, t, \\
& \sum_z (\mathrm{imp}_{lzt} - \mathrm{exp}_{lzt}) = 0, \quad \forall l, t,
\end{aligned} \tag{2}$$

where $C_{ztj}(q_{ztj})$ is the total generation cost from technology j in zone z and hour t with production quantity q_{ztj}. The technology j includes coal, diesel, natural gas, other thermal, hydro, solar, and wind. We allow the cost function $C_{ztj}(q_{ztj})$ to differ by zone and technology and explain details in the "cost functions" section below.[23] Instead of solving the model for each hour separately, we solve it for each week at a time to take into account the dynamic hourly linkages.[24]

The first constraint in equation (2) describes that supply plus net imports need to be larger than or equal to demand in each zone, after accounting for transmission losses. imp_{lzt} are imports into zone z coming from transmission line l, exp_{lzt} are exports out of zone z through transmission line l, and D_{zt} is demand in zone z. δ_1 represents a transmission loss factor for high-voltage transmission, which is relevant for transmission between zones. With this transmission loss, supply from imports can be expressed by $(1-\delta_1)\,\mathrm{imp}_{lzt}$. δ_2 is a transmission loss factor for low-voltage transmission, which is relevant for transmission inside each zone. With this transmission loss, the total supply needs to meet the adjusted demand quantity, $D_{zt}/(1-\delta_2)$.

The second constraint represents trade capacity constraints between zones. To model the trade between zones, we benefit from Chile's geography, as we can express the transmission network as a vertical line. Our model includes $l = 1, \ldots, L$ interregional transmission lines with net flow transmission capacity F_l, connecting each contiguous zone. f_{lz} is the transmission capacity of the line if zone z is connected to that line.[25] Finally, exports going out of zone z into zone r, connected via line l, need to equal imports in zone r coming via line l, which is represented in the last equation.

The operator minimizes the total cost with respect to the vectors of production quantities, imports, and exports (**q**, **imp**, and **exp**). The market clearing process produces equilibrium quantities, imports, and exports consistent with cost minimization. We also obtain

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

[23]Further details are also provided in Appendix B.

[24]We also have solved the model for each month at a time to check the robustness of our results, but the results are very similar to what we find with a weekly model. We use the weekly model as it allows us to better reflect water scarcity in a few weeks of 2018.

[25]For example, line 1 connects zones 1 and 2. Transmission capacity f_{1z} is only positive for the two regions connected with the line, and only after the interconnection. f_{1z} is zero for any other zone.

the market clearing prices at each zone (p_{zt}), defined as the shadow value on the demand constraint of each zone z.

We take advantage of the fact that many of the elements in the dispatch model are observable in our data, including production costs, hourly demand at the node level, hydro availability, and transmission grid. However, some of these variables do not map directly into our model. We take several steps to estimate each of its elements.

Network Model. We separate the Chilean electricity market into eleven zones from the north to the south, as shown in Figure A.2. All provinces in SING belong to one zone, as it was a physically isolated region before the interconnection.[26] We split the other provinces (i.e., provinces in SIC) into additional ten zones using the k-means clustering algorithm based on the time series of average nodal prices at the province level, in the spirit of Mercadal (2022).[27]

To estimate the transmission capacity between these eleven zones, we calculate trade flows between the zones in our data. Based on these trade flows, we set the available transmission capacity to the 95th percentile of the trade flows observed in the data.[28] Table A.II shows the estimated trade capacity between the eleven zones. We find that this approach captures well the transmission expansions created by the interconnection in 2017 and the reinforcement in 2019. For example, the transmission capacity for line 1 (the connection between SING and SIC) was expanded by about 600 MW by the interconnection, and the transmission capacity for lines 2 to 4 was expanded by about 1100 MW by the reinforcement. The eleven zones appear to do well at describing the main bottlenecks in the system, and the geographical split and transmission capacity appears to be consistent with engineering models of the Chilean electricity market, such as Haas, Cebulla, Nowak, Rahmann, and Palma-Behnke (2018), which features four zones.

Cost Functions. We allow the cost function $C_{ztj}(q_{ztj})$ to differ by zone and technology. For coal, diesel, and other nongas thermal generators, we directly use the unit-level marginal costs observed in the daily cost data.[29] In addition to the marginal costs, we also include ramping costs as parts of the cost function for coal power plants. Estimating these parameters is beyond the scope of our exercise, so we use parameters from engineering constraints and the existing empirical evidence (Wolak (2007), Reguant (2014), Gowrisankaran, Langer, and Zhang (2023))—we assume that coal power plants can only ramp up or down their production by 10% of their capacity at any given hour.[30]

[26] One commune in Antofagasta region, Taltal, belongs to SIC.

[27] Our algorithm is simpler than Mercadal (2022), as we do not add an outer loop to discipline the k-means clustering algorithm. In addition, we make certain adjustments to the result of the k-means clustering algorithm. The north and the south of Santiago are initially assigned to the same zone based on the algorithm because these two regions had similar time-series price variation. Because these two regions are not contiguous, we define these regions to be separate zones. We also define the Bio Bio region to be a separate zone to reflect bottlenecks that are not fully captured by the k-means algorithm.

[28] We do not use the maximum flow because our zones do not reflect the exact network configuration. The maximum flow constructed with our zone tends to be an outlier. We also constraint the trade constraints to be nondecreasing over time.

[29] For plants in SING, we observe daily costs. For plants in SIC, we observe daily costs for each of the three "blocks," where blocks are defined as 3 of the 8-hour segments of the day. Therefore, we use block-level daily cost for plants in SIC.

[30] We also extended the model to have startup costs. We set plants' minimum operational capacity (conditional on running) to 40% and set startup costs to the equivalent marginal costs of 8 hours running at minimum capacity as a proxy for the necessary fuel to start up a plant. However, the computational cost of adding startup

We also observe unit-level marginal costs for natural gas power plants. However, gas power plants usually have several marginal costs that differ by the type of long-term natural gas contract being used. Unfortunately, our data do not specify which natural gas contract is used for each hour or how much quantity of natural gas is available under each contract type consistently throughout the sample. Differences in marginal costs by contract type can be large, as some gas contracts have a zero marginal cost due to their take-or-pay nature. For this reason, we estimate an hourly zone-level supply curve for natural gas generators based on hourly nodal prices and observed hourly generation from natural gas power plants for every month of the sample. We also include limits to hourly generation set to the minimum and maximum observed generation at each month of the sample.[31]

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 zone level, as with natural gas. We regress equilibrium prices on the observed equilibrium quantities of hydro and estimate a week-of-sample supply curve. Additionally, we constrain the amount of water to be used during a week to equal the observed total amount used in that same period, to reflect the nature of limits to hydro availability.[32] 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 week of the sample.

Solar Capacity. To determine maximum and minimum capacities for solar power, we take advantage of the extremely predictable solar potential in the Atacama region and the Antofagasta region.[33] While our data are very detailed regarding solar output, we lack data on solar *curtailment*. Solar curtailment is important in our application, as indicated by the zero prices in the Atacama region before the transmission expansion. We estimate capacity factors by week of year and hour of day based on data from 2019, which is the period in which curtailment is less prevalent thanks to the reinforcement. Given that we do not observe zero prices during that period, we assume that curtailment is not occurring. We use these capacity factors times the installed (or counterfactual) capacity to model potential solar output in other years.

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 5 shows that it captures the evolution of prices in the data. The figure also shows that the model captures moments of scarcity in the system with price spikes. Table A.III in

costs was quite large due to the need to compute equilibrium solar investment for our counterfactuals. Yet, we found that the extended version of the model with startup costs did not improve the model fit compared to the main model with ramping cost because ramping costs sufficiently discipline coal production in the model (Figure A.6) and did not lead to significant differences in aggregate market outcomes or solar profitability. Therefore, we have decided to use the model that includes ramping costs but not startup costs.

[31]We include further details in Section Appendix B.

[32]We also have solved the model with daily 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.

[33]Solar potential and availability are 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. Figure A.4 plots the 10th and 90th percentile of the distribution of hourly capacity factors in zones 1 and 2. One can see that there is very limited variation in capacity factors even within an entire season. Monthly distributions are even tighter.

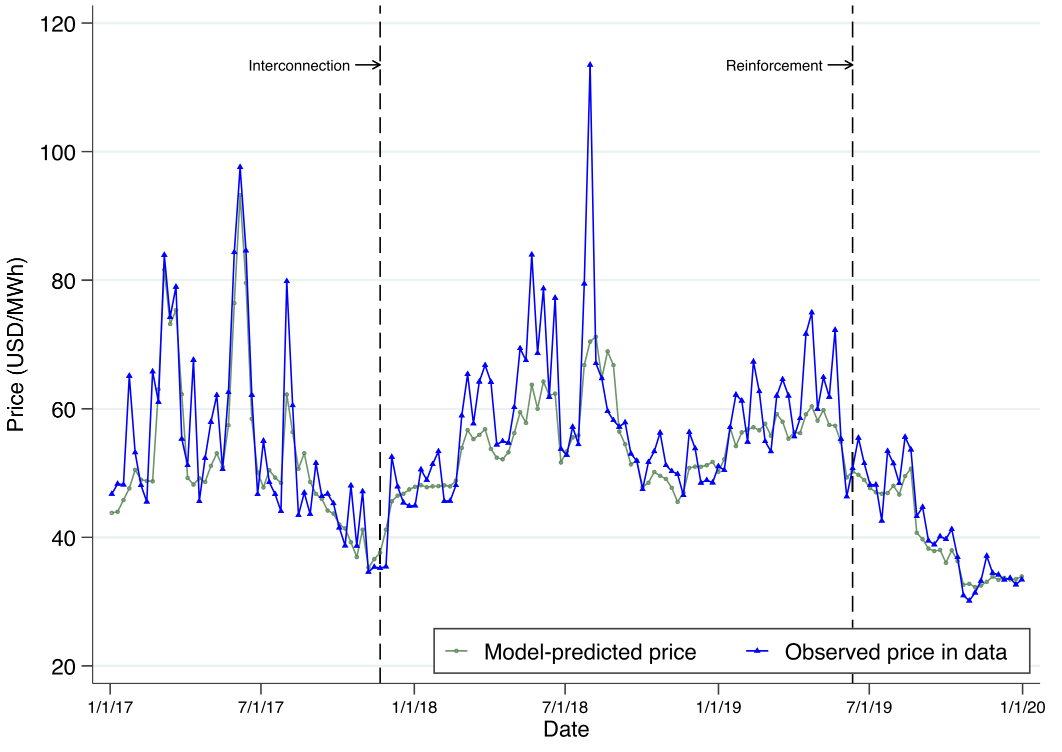


FIGURE 5.—Model fit: Model-predicted market price and actual market price in the data. *Note*: This figure compares the price predicted by the structural model described in Section 5 and actual prices in the data. Each dot represents the weekly average of hourly node prices from all nodes, weighted by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

the Appendix shows that we also match well the production attributed to each generation source across the three periods of study.[34] 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. Generation from the other fuel types is also relatively well matched, except for the share of coal at the end of the sample, which our model overpredicts. This is because the transmission line makes coal from the northern zones more attractive in our model.[35]

5.2. *Investment Model*

The second part of the model is an investor's decision regarding investment in new renewable plants. Our primary objective is to model and estimate how solar investment

[34]In the Appendix, we investigate why our model does not fully predict the price spike in August 2018. The price spikes occurred only in zones 4–11 in a short period between August 1 and 6 in 2018 (Figure A.12). During this period, the hydro availability was low in the south (Figure A.13), and there was idiosyncratic transmission congestion within zone 4. These two factors made high-cost diesel plants in the south dispatched only for a few days (Figure A.14), causing high-node prices in zones 4–11. Our model does not capture this idiosyncratic transmission congestion within a zone. To avoid overfitting, we decided to keep the model parsimonious without adding idiosyncratic constraints that could be more arbitrary.

[35]Note that this will tend to reduce the value of the line due to greater environmental externalities than those observed in the data and, therefore, affect our cost-benefit analysis conservatively.

TABLE III

SOLAR GENERATION MARKET SHARES IN ZONES 1 AND 2.

Firm Name	Solar Generation Market Share	System-Level All Generation Market Share
ENEL	23.9%	24.4%
SunEdison	11.4%	1.3%
ACCIONA	8.8%	1.9%
First Solar	8.5%	0.7%
Ingenostrum	7.7%	0.6%
Pattern Energy	6.5%	0.5%
EIG	6%	0.5%
AustrianSolar	4.2%	0.3%
Etrion Corp.	3.9%	0.3%
Actis	3.7%	0.8%
Element Power Chile	3.2%	0.3%
X-Elio	3.2%	0.2%
Solar Pack	2.4%	0.2%
Solairedirect	1.9%	0.2%
AES ANDES	1.3%	27.3%
Distributed Power Partners	0.6%	0%
APOLO DEL NORTE SPA	0.6%	0%
Oxum	0.5%	0%
Distributed Power Partners	0.5%	0%
SOLAR BROTHERS SPA	0.5%	0%
Others (8 firms)	0.9%	8.9%

Note: This table shows solar market share and overall market share for the companies that own solar plants in zones 1 and 2. “Solar generation market share” is the market share among solar generation in zones 1 and 2 during December 2019. “System-level all generation market share” is the company’s market share in the entire system, including all technologies, during December 2019; this column does not add up to 100% because there are companies who do not own solar plants in zones 1 and 2. The Herfindahl–Hirschman index (HHI) based on these market shares is 1066, which suggests a competitive environment for the entries of solar plants.

changes in response to changes in trade capacity between zones. With this investment model and the dispatch model described in Section 5.1, we can simulate counterfactual scenarios with different levels of transmission capacity.

We assume that entry into solar power generation is competitive and then solve for the equilibrium solar investment that is consistent with a zero-profit entry condition presented below. The assumption of a competitive environment in the entry of solar power is consistent with our data. First, we show solar generation market shares in solar-intensive regions, zone 1 (Antofagasta) and zone 2 (Atacama), in Table III. Enel is the largest firm, with 24% solar generation market share, but the other 76% of the shares consist of many firms, including smaller-scale new entrants. The Herfindahl–Hirschman index (HHI) based on these market shares is 1066, which suggests a competitive environment. While some large incumbent firms such as AES have not invested in the early deployment of solar, several others have entered the market. Second, we find that many suppliers participated in the auctions for the Power Purchase Agreement (PPA), and the data suggest that these auctions were competitive.[36]

[36]For example, 38 firms participated in the 2015 auction, of which 5 won; 84 firms participated in the 2016 auction, of which 22 won; 24 firms participated in the 2017 auction, of which 5 won; and 29 participated in 2021 auction, of which 5 won.

With the market clearing process in equation (2) in mind, renewable investors will expand investment in new renewable plants k until the following zero-profit condition at a given zone is satisfied:

$$E\left[\sum_{y\in Y}\frac{\sum_h p_{zyh}(\mathbf{k})\times q_{zyh}(\mathbf{k})}{(1+r)^y}\right]=c_z\,k_z,\quad \forall z, \tag{3}$$

where y indexes a year, h indexes an hour, r is the discount rate, p_{zyh} is the market clearing price at zone z from the solution of equation (2), k_z is solar capacity in zone z, and $\mathbf{k}$ is a vector of solar capacity in each zone. Due to the direct cannibalization effect of solar power on market prices, the marginal revenue of solar investment is decreasing in k_z. As we explain below, we use data on $\mathbf{k}$, the dispatch model in equation (2), and the equilibrium condition in equation (3) to estimate c_z, which is the investment cost per unit of capacity at zone z. To model market expectations in the long run, we use the distribution of fundamentals (demand and costs) from data in 2018 and 2019. We assume that once built, solar panels last for 25 years, which is the standard lifespan of a panel assumed in the industry.[37]

In principle, we could solve for solar investment in every zone, but it would be computationally complex. We focus on solar in zones 1 (Antofagasta) and 2 (Atacama) because most of utility-scale solar investment occurs in these two zones. The latitude and radiation in the north of Chile make these areas substantially more productive than other parts of the country and, therefore, these two regions play a major role in the expansion of solar power.

The first step is to estimate c_z based on the data and equation (3). Our data provide the observed levels of solar investment (k_z). With these investment levels and transmission constraints in the presence of the interconnection and reinforcement, we can run the dispatch model in equation (2) to obtain the equilibrium $p_{zyh}(k_z)$ and $q_{zyh}(k_z)$. For the interest rate r, we use $r = 0.0583$ based on Moore, Boardman, and Vining (2020).[38] These variables and equation (3) allow us to estimate c_z. We find that $c_1 = 1.84$ and $c_2 = 1.67$ million per MW installed.

The second step is to run counterfactual policy simulations based on the data, equations (2) and (3), and the estimated c_z. We can change f_{lz} in equation (2) to reflect transmission capacity in a counterfactual scenario. With these counterfactual levels of transmission constraints, we solve for the dispatch model at a given level of solar investment k_z. The solution of the dispatch model produces the equilibrium hourly prices and production, $p_{zyh}(k)$ and $q_{zyh}(k_z)$, at a given k_z. We search for the equilibrium k_z^* that satisfy the zero-profit condition (3) in each zone as well as dispatch model in equation (2).[39] We use this procedure to run counterfactual policy simulations in Section 5.3.

[37]Our investment model focuses on the equilibrium quantity of solar investment without explicitly modeling the investment path (i.e., the timing of investment over time). This simple model is parsimonious yet allows us to examine the core of our research question: the equilibrium solar investment with and without market integration. While we believe that this model is well suited to our context and research question, we want to note that alternative investment models can be more suitable in other contexts, especially when the focus of research is the analysis of investment paths.

[38]This number is nearly identical to 0.06, the discount rate used by the Chilean government for their public investment projects.

[39]We use a simple grid search method to find k_z^*. We begin with the observed solar investment levels k_z and reduce it with a 5% increment to find k_z that is close to k_z^*. Around that point, we further use a 1% increment to find k_z^* that satisfies equations (3) and (2).

Because solar profitability is weakly decreasing in k_z^*, we can ensure that there is a unique value of investment at each zone for which the zero-profit condition is satisfied. Note that, in general, the equilibrium solar investments (k_z^*) in equation (3) may not be unique when there are multiple zones. In our application, uniqueness holds because the zones for which we solve for investment are independent of each other. In our counterfactuals, we solve for solar investments in zones 1 and 2 when there is no market integration, and thus the profitability of one region does not depend on the level of investment in the other region.

Goodness-of-Fit. Admittedly, the investment model in equation (3) is a stylized representation of the investors' expectations and solar investment in this market. However, even with such a stylized model, our estimated costs per MW installed (c_1 and c_2) are on a similar order of magnitude as the solar installation costs observed in our data. In the power plant investment data collected by the CLAPES UC-CBC, we observe completion dates and costs for large-scale solar installations at the plant level.[40] For the 107 completed projects in all regions, the average cost is 1.95 million dollars per MW. For projects at the end of our sample period, five solar plants in zone 1 and another five in zone 2 were completed from 2017 to 2019, with a capacity-weighted average cost of 1.97 million per MW for zone 1 and 1.63 for zone 2. The costs estimated from our estimation ($c_1 = 1.84$ and $c_2 = 1.67$) fall within this range.

5.3. *Simulating the Benefits From Market Integration*

In this section, we use the model presented in Sections 5.1 and 5.2 to solve for the market equilibrium for three scenarios that help us quantify the impact of market integration with and without investment effects. As described in Section 5.2, we use the distribution of fundamentals, such as hourly demand and daily costs, from data in 2018 and 2019 (the last 2 years of our sample period) to model market expectations in the long run. The first scenario is *Actual scenario*, in which transmission capacity is expanded by the interconnection and reinforcement, as it actually happened in Chile. This scenario serves as our baseline.

As a second scenario, we simulate a counterfactual as if the interconnection and reinforcement lines had not been built. The absence of market integration would reduce the profitable level of solar investment, but we purposely hold solar investment fixed in this scenario. Instead of solving for equation (3), we assume that solar investment remains the same as *Actual scenario*. With this solar investment level, we change f_{lz} in equation (2) to reflect the transmission constraints in the absence of the interconnection and reinforcement. We call this second scenario *No market integration*.

In a third scenario, we further incorporate the investment effects due to the lack of market integration. We change f_{lz} in equation (2) to reflect transmission capacity in the absence of the interconnection and reinforcement. With these counterfactual levels of transmission constraints, we simultaneously solve for the dispatch model in equation (2) and investment model in equation (3) to find the equilibrium solar investment, dispatch quantities, and market cleaning prices, as described in Section 5.2. For expositional purposes, we find it helpful to show the counterfactual solar investment level as a percentage

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

of what is built in *Actual scenario*. We call this third scenario *No market integration (with reduced investment)*.[41]

Panel A in Figure 6 shows the equilibrium prices at noon in the Atacama region for the three scenarios. The actual scenario (market integration), which is the first scenario simulated by our model, shows the same pattern as what we see in the observed data in Figure 4. The price is often zero before the interconnection in 2017 because some solar production cannot be exported to other regions. After the interconnection, the price increases to around 50 USD/MWh as this region can export solar power to other regions. In contrast, in the counterfactual scenario of no market integration when these solar investments remain, the price would not increase and continue to be zero for many days because some solar production still cannot be exported to other regions. This is certainly not a realistic equilibrium in the long-run because solar power would be unprofitable.

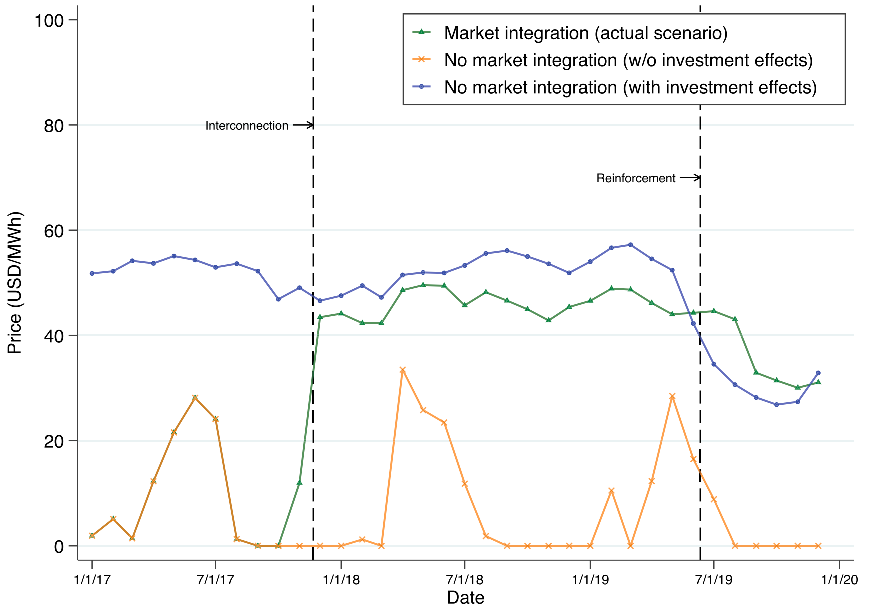
Once we account for reduced investment due to the lack of transmission, we find that only a small portion of the observed solar capacity would have entered in the absence of market integration, based on the assumption that investors need to have the net present value of their investments become positive in 25 years. Our counterfactual simulation results show that the equilibrium solar plant capacity in zone 1 (Antofagasta) and zone 2 (Atacama) would be 20% and 17% of the solar capacity in the actual scenario, respectively. These reductions in solar investment bring the equilibrium prices back up to higher levels, as shown in Panel A in Figure 6.

Panel B in Figure 6 presents solar generation (GWh/day) for the three scenarios. After the interconnection in 2017, we observe a higher level of solar generation in the actual scenario compared to the counterfactual scenario of no market integration when solar investments remain. This difference shows how much solar power cannot be produced without market integration because of the inability to export solar power (i.e., curtailment). One can see that curtailment increases as solar capacity grows, representing a substantial share of output. Table IV shows that curtailment in zone 2 is 16% on average at the end of the period (column 2). Once investment reductions due to the lack of transmission are accounted for (column 3), the difference in solar production is much larger, with solar generation remaining substantially below what is observed in the actual scenario and curtailment becomes negligible.

In columns 1 to 3 in Table IV, we provide a summarized quantitative comparison between these three counterfactuals. Column 1 shows the actual scenario, column 2 shows the counterfactual scenario of no market integration keeping investment fixed, and column 3 incorporates a reduction in solar investment due to the lack of market integration. Using the results in this table, we examine additional theoretical predictions described in Section 2. Market integration increases solar production by 10% if we ignore the investment effects and 178% if we incorporate them. In line with Observation 1, in the presence of anticipated solar investments, ignoring investment effects understates the reduction in generation costs—it predicts a reduction in generation costs of 3% on average (7% at noon, an hour with high solar generation). Once we incorporate the investment effects, the reduction in generation costs is 8% on average and 18% at noon. These results also

[41]We can define the entry threshold as a percentage because solar production in the Atacama desert is very homogeneous. Therefore, the location of the solar panels is not as relevant as in other applications (e.g., more heterogeneous solar areas or wind power applications). Figure A.4 in the Appendix shows that the range between the 10th and 90th quantile of solar output is very narrow in the northern part of Chile. Note that part of the range is directly explained by the solar movement within a season. Within-month variation is even smaller.

Panel A: Prices in Atacama (Renewable-Intensive Region)



Panel B: Solar Generation

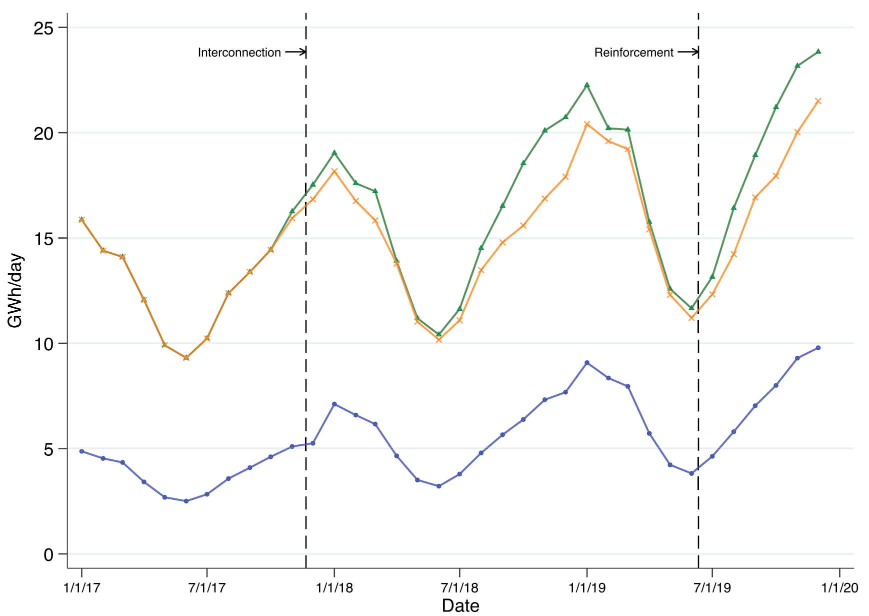


FIGURE 6.—Counterfactual simulation results. *Note*: We use the structural model and counterfactual simulations described in Section 5.3 to compute market equilibria for three scenarios. The first scenario is the actual scenario in which market integration happened (the interconnection in November 2017 and the reinforcement in June 2019). The second scenario is a counterfactual case in which the market integration did not happen (no market integration w/o investment effects). The third scenario is equivalent to the second but with investment effects—some entry would not happen without market integration because such an investment would become unprofitable. Panel A shows the monthly averages of the wholesale electricity prices (USD/MWh) in Atacama region (zone 2). Panel B shows the monthly average of total daily solar electricity generation (GWh/day).

TABLE IV

COUNTERFACTUAL SIMULATIONS TO ESTIMATE THE IMPACTS OF MARKET INTEGRATION.

	(1)	(2)	(3)	(4)	(5)
	Market Integration (Actual Scenario)	No Market Integration (Counterfactual Scenarios)		Impact of Integration	
				(1)–(2)	(1)–(3)
Modelling assumption					
Investment effect due to lack of integration		No	Yes	No	Yes
Solar power in Antofagasta (zone 1)					
Investment relative to actual	100%	100%	20%		
Investment in MW	693.5	693.5	138.7	0	554.8
Revenue per MW ($1000)	133.5	122.6	133.6	10.9	−0.1
Daily solar curtailment (MWh)	0	0	0	0	0
Solar output relative to solar potential (%)	100	100	100	0	0
Solar power in Atacama (zone 2)					
Investment relative to actual	100%	100%	17%		
Investment in MW	1084	1084	184.3	0	899.7
Revenue per MW ($1000)	121.5	26.5	121.3	95	0.2
Daily solar curtailment (MWh)	0	1412.7	0.3	−1412.7	−0.3
Solar output relative to solar potential (%)	100	83.9	100	16.1	0
System-level solar production					
Daily solar production (GWh)	17.5	16	6.3	1.5 (+10%)	11.2 (+178%)
Price ($/MWh)					
Daily price (system-level)	49.4	51.1	53.3	−1.7 (−3%)	−3.9 (−7%)
Hour 12 price (system-level)	48.5	48.4	54.1	0.1 (+0%)	−5.6 (−10%)
Hour 12 price in Antofagasta (zone 1)	44.9	42.1	45.1	2.8	−0.2
Hour 12 price in Atacama (zone 2)	46.1	6.5	46.4	39.6	−0.3
Hour 12 price in Santiago (zone 6)	52.6	60.5	60.8	−7.9	−8.2
Price difference (Santiago–Atacama)	6.4	54	14.4	−47.6	−8
System-level cost ($/MWh)					
Daily cost	36	37.2	39.1	−1.2 (−3%)	−3.1 (−8%)
Hour 12 cost	31.4	33.8	38.4	−2.4 (−7%)	−7 (−18%)
Generation by fuel (%)					
Solar	8.3	7.6	3	0.7	5.3
Wind	5.8	5.6	5.8	0.2	0
Hydro	28.5	28.6	28.6	−0.1	−0.1
Coal	40.4	38.2	41.9	2.2	−1.5
Gas	13.4	16.4	17	−3	−3.6
Other thermal	3.5	3.5	3.6	0	−0.1
Emission (1000 tons of CO_2)					
Daily CO_2 emission	80.9	78.7	85.5	2.2 (+3%)	−4.6 (−5%)

Note: Column 1 shows the actual scenario (with market integration), columns 2 shows the counterfactual scenario of no market integration keeping investment fixed, and column 3 incorporates a reduction in solar investment due to the lack of market integration. Columns 4 and 5 show the impact of integration with and without the investment effect. For solar power in zones 1 and 2, we present counterfactual solar investment level, annual revenue per MW installed capacity, the average daily curtailment of solar, and the average ratio of daily solar output relative to solar potential. For system-level prices, we show average daily generation-weighted price and generation-weighted price at hour 12. For zone-level prices, we simply show the average price over a year. Additionally, we also show average daily generation share by fuel type and the average daily CO_2 emission.

imply that 3% is an upper bound on the *net* benefits of investment accounting for solar investment costs, as shown in Observation 1 in Section 2.

The equilibrium prices presented in Table IV suggest that market integration can successfully reduce prices at the system level. The prices in columns 1 to 3 are consistent with the theoretical prediction from Observation 2 in Section 2. In the presence of anticipatory investment, price reductions from market integration would be underestimated if the investment effects are not incorporated. Indeed, the price reductions from column 2 to column 1 are underestimated compared to the reductions from column 3 to column 1.

Furthermore, 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 investment effects, the price in Atacama is predicted to be very low in the absence of market integration (6.5 USD/MWh in column 2). This is because it ignores the fact that some solar entry would be unprofitable without market integration. As a result, the impact of market integration on price convergence between these two regions is overstated when investment effects are ignored, as shown in Observation 3 in Section 2. Column 2 suggests that if we ignore the investment effects, the price difference between Atacama and Santiago is 54 USD/MWh with no market integration and 6.4 USD/MWh with market integration. Thus, it is tempting to conclude that the price convergence effect of market integration is 47.6 (= 54 − 6.4) USD/MWh. However, once the investment effects are accounted for in column 3, the price difference without market integration is 14.4 USD/MWh, implying that the price convergence effect is 8 (= 14.4 − 6.4) USD/MWh.[42]

6. COST-BENEFIT ANALYSIS OF TRANSMISSION INVESTMENTS

According to the Chilean government, the costs of the interconnection and the reinforcement lines were $860 million and $1 billion, respectively (Raby (2016), Isa-Interchile (2022)). These transmission expansions initially presented doubts regarding their economic benefits. For example, Financiero (2013) describes that consumers at first considered that the costs of new transmission lines may exceed the benefits of a unified market. Discussing the benefits to consumers is important, as these line expansions were paid via an increase in energy fees by consumers.[43]

In Table V, we use results in Table IV to calculate the benefits of market integration. We show alternative measures of surplus, including savings in consumer costs, savings in generation costs, and savings from reduced environmental externalities, because the most relevant benefit measures often depend on what question policymakers have.

The first benefit measure we show is savings in consumer costs that are generated from grid expansions. We obtain the change in consumer surplus by multiplying electricity demand with the price difference between the full integration scenario and the rest. We implicitly assume that consumer demand is not directly affected by the transmission line project. This should be seen as a conservative assumption regarding the benefits of the line, as renewable power in Chile, partially enabled by expanded transmission, has substantially brought down the costs of energy in the country. We find that the market integration reduces consumer cost by $176 million per year if we ignore the investment effect

[42]Note that Observation 3 is derived under the assumption that market integration results in full price convergence. As shown by the column under the actual scenario, we observe that regional prices converge, but the convergence is incomplete.

[43]In 2015, the government of Chile held a public auction to construct the transmission line. In this auction, the objective was to minimize the cost of construction that consumers pay in the tariff associated with electric transmission.

TABLE V

COST-BENEFIT ANALYSIS OF TRANSMISSION INVESTMENTS.

	(1)	(2)
Modelling assumptions		
Investment effect due to lack of integration	No	Yes
Benefits from market integration (million USD/year)		
Savings in consumer cost	176.3	287.6
Savings in generation cost	73.4	218.7
Savings from reduced environmental externality	−161.4	249.4
Increase in solar revenue	110.7	183.5
Costs from market integration (million USD)		
Construction cost of transmission lines	1860	1860
Cost of additional solar investment	0	2522
Years to have benefits exceed costs		
With discount rate = 0	14.8	6.1
With discount rate = 5.83%	>25	7.2
With discount rate = 10%	>25	8.4
Internal rate of return		
Lifespan of transmission lines = 50 years	6.95%	19.67%
Lifespan of transmission lines = 100 years	7.23%	19.67%

Note: This table presents different components of the costs and benefits of market integration. The benefits of the transmission lines include (1) savings in consumer cost, which is the product of price and demand, (2) savings in system-level generation cost, (3) monetized savings from reduced environmental externality due to thermal power generation, and (4) increase in *total* solar revenue in zones 1 and 2. The costs of market integration include the construction cost of the transmission lines and the additional cost of solar investment in zones 1 and 2 (because with investment effects, market integration could lead to higher solar investment). We show the number of years required to recover the cost of market integration under different assumptions of government discount rates as well as the internal rate of returns with different assumptions for the lifespan of transmission lines.

in column 1. The consumer saving is substantially larger and estimated to be $288 million per year when the investment effects are incorporated in column 2.

In addition to considering consumer surplus, the line expansion could have reduced negative emissions externalities (Fell, Kaffine, and Novan (2021)) due to the replacement of thermal generation. Market integration might have reduced both global pollutants (CO_2) and 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. We use this information to calculate the reduction in electricity production from each type of thermal plant 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).[44]

The remaining rows in Table V provide a cost-benefit analysis of transmission investments. In our calculation, the cost of market integration consists of the construction cost of the two transmission lines ($1860 Million USD) and the "additional" solar investment costs that come from the increase in solar investment driven by the market integration. The benefit consists of savings in consumer costs, benefits in solar revenues, and reductions in environmental externalities. For the discount rate, 5.83% is a relevant reference point because this is the discount rate commonly used for public investment in Chile

[44] Greenstone and Looney (2012) estimate that the noncarbon external cost is 3.4 cents per kWh for coal generation and 0.2 cents per kWh for natural gas generation. Carleton and Greenstone (2021) calculate a social cost of carbon to be $125/ton CO_2.

(Moore, Boardman, and Vining (2020)). To examine how the cost-benefit results vary with the assumption on the discount rate, we also report results with 0% and 10% discount rates.

First, we calculate how many years are required to have the benefits of market integration exceed its cost. Column 1 implies that if we ignore the investment effects, it takes 14.8 years to recover the cost of the investment with a 0% discount rate and more than 25 years with higher discount rates. Column 2 suggests that the cost-benefit is much more attractive, with a recovery time of 7.2 years with a 5.83% discount rate when the investment effect is included. This finding implies that ignoring investment effects substantially understates the benefit of the transmission expansion.

Second, we also calculate the internal rate of return (IRR) of the transmission investment in Table V. To calculate the IRR, we need to assume the lifespans of the transmission lines. For new transmission lines in our sample period, a conservative estimate for the lifespan is about 50 years according to industry reports. However, historically, many countries have used transmission lines over 100 years in practice.[45] Therefore, we provide results for each of the 50-year and 100-year lifespan, although our results do not vary between the two assumptions on the lifespan. With a 50-year lifespan, the IRR is 6.95% if we do not incorporate the investment effect and 19.67% once we incorporate the investment effect. With a 100-year lifespan, the IRR is 7.23% if we do not incorporate the investment effect and 19.67% once we incorporate the investment effect. Thus, in our application, the IRR does not change much between the 50-year and 100-year assumptions on the lifespans of transmission lines, but it changes significantly when the investment effect of market integration is incorporated.[46]

Discussion of Limitations. There are several limitations to our cost-benefit calculations. In several respects, our calculation is likely to understate the benefits of market integration for at least three reasons. First, coal and natural gas prices were lower than the historical average in our sample period. As these fuel prices return to historical averages in the future, the benefit of renewable power would be larger than in our calculation. Second, our calculation includes the benefits from the entry of solar plants only up to the end of our sample period and does not include potential benefits from additional entrants 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. Third, before the renewable expansion, Chile relied on imports of natural gas and coal to generate large amounts of electricity, which had been an energy security problem. Therefore, renewable expansion provided a benefit of energy security for the country, which is not incorporated in our calculation. Finally, while we focus here on the time to recover the investment, transmission investments are very long-lived and will continue to provide benefits for several decades.

Another limitation is that our simulations take solar investments in nonsolar-rich areas into account but do not allow them to respond to alternative transmission configurations. Because solar power in the north of Chile has unparalleled radiation potential, and land

[45] For example, Perras (2015) shows that the lifespan of transmission lines are between 80 and 120 years, and some parts such as aluminium conductors may need to be replaced every 40 years.

[46] We calculate the IRR using a standard definition. Denote c_0 be the total cost of market integration, b_t be the annual benefit from the integration, and T be the lifespan of transmission lines. The IRR satisfies $\sum_{t=0}^{T} \frac{b_t}{(1+\text{IRR})^t} = c_0$. In our application, the IRR with the investment effect of market integration is nearly identical between the 50-year (0.19671) and 100-year (0.19674) assumptions on the lifespans of transmission lines because it does not change much with T once T is large enough.

near Santiago is much more scarce, this limitation might not be as relevant as in other applications.[47] However, ignoring this margin makes our cost-benefit more favorable because if Chile did not integrate the market, solar investment in nonsolar-rich areas could have increased solar capacity. Unfortunately, allowing endogenous investment in these regions would require substantial assumptions because we have much more limited information on the cost of installed solar as there are a lot fewer large-scale solar investments in these regions in our sample period. In addition, our model does not model detailed aspects of land use, as we benefit from the fact that land in the north of Chile is cheap and homogeneous. Therefore, we want to note that an additional analysis along these lines would be an important topic for further research.

7. CONCLUSIONS

We study the impacts of market integration on renewable energy expansion with an emphasis on investment effects. Our theory highlights that market integration improves allocative efficiency by gains from trade and it incentivizes new entry of renewable power plants. Using two recent grid expansions in the Chilean electricity market, we examine how this market integration changed market prices, generation costs, and renewable investments. Based on the insight from this descriptive evidence, we build a structural model of power plant entry to quantify the impact of market integration with and without the investment effects. We find that market integration resulted in price convergence across regions, increases in renewable generation, and decreases in generation cost and pollution emissions. Furthermore, a substantial amount of renewable entry would not have occurred in the absence of market integration. Our findings suggest that ignoring these investment effects would substantially understate the benefits of market integration and its important role in expanding renewable energy.

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[47]The Atacama desert has among the best worldwide solar potential factors. According to the Global Solar Atlas (https://globalsolaratlas.info/), an industry-scale installation near Santiago would get around 2100–2200 kWh/m^2 per year in ideal installations. In comparison, the same installation in Atacama would get above 2800 kWh/m^2, making them at least 30% more efficient. To this difference, one needs to consider adding the fact that land use restrictions and costs per m^2 in Santiago are potentially much larger.

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