Econometrica Supplementary Material

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

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APPENDIX A: PROOFS

PROOF OBSERVATION 1: First, we need to show that gross gains from trade are the largest in the comparison with investment effects.

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

$$\text{Gains Trade} - \text{Gains Trade}_{\text{no invest}} = \frac{\beta^A \beta^B}{2(\beta^A + \beta^B)} q^{\text{solar}}\left(2D - q^{\text{solar}}\right) > 0,$$

  for a relevant well-defined solution, as $q^{\text{solar}} < D$.
- If the investment has already been realized, then the distortion comes in the "before" period. We need to show that autarky costs are smaller with anticipated investment, which is also trivial in a general setting as, for any positive q^{solar}, total gross costs go down. Numerically,

$$\text{Gains Trade} - \text{Gains Trade}_{\text{invest early}} = \beta^A q^{\text{solar}}\left(D^A - \frac{q^{\text{solar}}}{2}\right) > 0,$$

  which is well-defined for $q^{\text{solar}} \leq D^A$. If $q^{\text{solar}} > D^A$, then it is also true as the difference in gains from trade becomes simply $(\beta^A D^{A2})/2$, the costs of producing under autarky in the north.

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

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

$$\frac{\beta^A \beta^B}{\beta^A + \beta^B}\left(D - \frac{q^{\text{solar}}}{2}\right) > c,$$

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

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

$$\beta^A\left(D^A - \frac{q^{\text{solar}}}{2}\right) < c,$$

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

PROOF OBSERVATION 2: Price reductions being understated can be shown very generally. In full equilibrium, price reductions are $\overline{p} - p^{**}$, where $\overline{p}$ is the average price under autarky.

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

PROOF OBSERVATION 3: Under the assumption that prices converge after the interconnection, then price convergence is defined by the difference in the early period. Taking advantage that we have assumed that $p^A \leq p^B$:

- If investment is anticipated, $\tilde{p}^A \leq p^A$, and thus $p^B - \tilde{p}^A > p^B - p^A$.
- If investment is delayed, price differences are not distorted.

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

If the constraint is binding, price differences will be weakly larger with solar investment. Visually, the offer curve from the north with solar is always to the right of the offer curve without solar. Therefore, for a restricted level of trade, the price difference will always be weakly larger with solar investment. Therefore, convergence will be higher without investment and binding transmission constraints. *Q.E.D.*

APPENDIX B: SHORT-RUN DISPATCH MODEL DETAILS

We present here a fully-fledged characterization of the short-run model with all the constraints explicitly spelled out. The short-run model is solved on a weekly basis. The model solves for a weekly dispatch solution that minimizes the costs of production. The subscript t indicates the time index for a given hour. Each weekly model contains 168 hours.

Variables. We solve for the following variables:

- q_{it}: Generation of each thermal unit, excluding natural gas, at most equal to the unit's capacity.

- q_{zt}^{gas}: Natural gas generation at each zone, subject to usage constraints (hourly min, hourly max).
- q_{zt}^{solar}: Solar generation at each zone, at most equal to available solar power that hour–day.
- q_{zt}^{wind}: Wind generation at each zone, at most equal to available wind power that hour–day.
- q_{zt}^{hydro}: Hydro generation at each zone, subject to seasonality and usage constraints (hourly min, hourly max, and total availability).
- D_{zt}: Output reaching final consumers at each zone, equal or greater than demand, when there are constraints that require spilling power beyond renewables (e.g., due to autarky counterfactuals in which must-run production is higher than demand in a given region).
- imp_{lzt}: Power imported to zone z via transmission line l.
- exp_{lzt}: Power exported from zone z via transmission line l.

Objective Function. The planner minimizes the costs of production:

$$\min \sum_{z,t}\left(\sum_{i\in z} c_{it}\, q_{it} + C_{zt}^{\text{gas}}\left(q_{zt}^{\text{gas}}\right) + C_{zt}^{\text{hydro}}\left(q_{zt}^{\text{hydro}}\right) + c^{\text{solar}}\, q_{zt}^{\text{solar}} + c^{\text{wind}}\, q_{zt}^{\text{wind}}\right).$$

The costs of coal, diesel, and cogeneration generation at the unit level come from the regulatory data. For SING, we use daily cost bids offered into the market. For SIC, we use block cost bids. Because coal units are subject to ramping constraints, we also include a limit in how fast a given coal unit can adjust its output. Specifically, a coal unit can only change its production at most by 10% of its capacity from hour-to-hour. Including ramping constraints creates hourly links in the decision of coal output for each unit.[48] We define unit-level capacity to be the 99th percentile of observed hourly generation.[49] For cogeneration units, we further restrict their hourly capacity to be at the observed generation level.[50] Finally, we also take into account unit unavailability potentially caused by maintenance or repair. We define a unit to be unavailable if it has zero production for the entire week and in that week, the average price is above the average cost for that unit.

The costs for natural gas production can be approximated based on the same bidding data. However, we face the challenge that not all cost bids that are offered into the market are available due to gas supply limitations. The system operator's algorithm takes into account not only costs but also gas stocks to optimize production, which we do not observe consistently in our sample. Therefore, we estimate a supply curve at the zone-month level based on realized gas production rather than offered bids. We fit the supply curve as a piecewise linear function, which is attractive for optimization. For every zone-year-month, we regress the generation-weighted average price in each zone on total natural gas production in that zone. The curve has two breakpoints at the 75th and 90th

[48]For the ramping constraints in the first hour of a week, the model takes as given coal generation from the final hour of last week.

[49]On top of the capacity constraints, we assign a lower bound to the production of a coal power plant in zone 2 (TER GUACOLDA). It has nonzero production even under zero prices, which is something that is hard to replicate with our model. The lower bound is set to be the 5th percentile of the plant's hourly observed generation in our sample period.

[50]This is because the capacity of cogeneration units in a given hour is subject to other availability constraints, which we do not observe. Using the 99th percentile of generation as the capacity for cogeneration units can significantly overestimate their availability for certain hours.

percentile of generation, with the constraint that the curve is weakly increasing and convex.[51] We also include lower bound and upper bound for natural gas production for each zone-year-month, which is the minimum/maximum hourly observed gas production.

The data for hydro costs could also be taken from the cost bids. However, we face a similar challenge to the case of natural gas, as hydro production is subject to many more constraints than those reflected in the cost bids. We approximate the supply of hydro as a linear function, given that hydro production at the zone level is the conjunction of several interrelated plants. For each zone-year-week, we regress the generation-weighted average price of hydro plants on total hydro generation in that zone. The coefficient and constant define the hydro supply curve observed during those weekly conditions.[52] We additionally include a lower and upper bound to hydro production based on the minimum and maximum observed hydro generation in that zone-year-week.[53]We also take as given hydropower as must-run in zone 2.[54]

We include a small marginal cost to solar and wind production to break ties in the presence of oversupply of renewable production.

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

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

Rows represent each zone (dim = 11) and columns represent each line (dim = 10). Ten segments go from north to south. Zone 1 is only connected to zone 2 via line 1; zone 2 is connected to 1 (line 1) and 3 (line 2), etc. In sum, line 1 connects 1 and 2; line 2 connects 2 and 3; line 3 connects 3 and 4; line 4 connects 4 and 5, etc.

The flow variables reflect net flows between zones and are defined as positive variables. For a given line l and zone z, the import or the export is positive, but not both. Exports from zone z in line l appear as imports to the zone to which the line connects. Exports and imports are limited by the size of the line, F_l. The size of the line can change depending

[51]Whenever the weakly increasing constraint is binding, we set the slope of the supply curve equal to zero and the constant term as the mean (generation-weighted average price) in that zone-year-month.

[52]We constrain the supply curve to be nondecreasing. Similar to the case of natural gas, whenever this constraint is binding, we set the slope equal to zero and the constant term as the mean (generation-weighted average price of hydro plants) in that zone-year-week.

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

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

on the scenario considered:

$$\begin{aligned}
&0 \leq \mathrm{imp}_{lzt} \leq T_{lz} L_l, \quad \forall l, \forall z, \forall t, \\
&0 \leq \exp_{lzt} \leq T_{lz} L_l, \quad \forall l, \forall z, \forall t, \\
&\sum_z (\mathrm{imp}_{lzt} - \exp_{lzt}) = 0, \quad \forall l, \forall t.
\end{aligned}$$

This definition of flows (separating imports and exports) adds some redundancy but allows us to penalize inflows with high-voltage transmission losses asymmetrically. This is reflected in the market clearing constraint:

$$\sum_{i \in z} q_{it} + q_{zt}^{\mathrm{gas}} + q_{zt}^{\mathrm{hydro}} + q_{zt}^{\mathrm{solar}} + q_{zt}^{\mathrm{wind}} + \sum_l \delta\, \mathrm{imp}_{lzt} - \sum_l \exp_{lzt} = \frac{D_{zt}}{1-\phi}, \quad \forall z, \forall t,$$

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

Prices. The social planner problem does not have explicit prices. Instead, the hourly prices are defined by the shadow value of the market clearing constraint above, which reflects the marginal cost of serving an additional unit of demand at a given region and time zt.

Computation. The model is solved for each week in our sample using the Julia language and the JuMP modeling library. We use the Gurobi solver, which is available for free under an academic license.

APPENDIX C: ANALYSIS OF MARKET POWER IN THE COST-BASED DISPATCH

As described in Section 3.2, Chile uses cost-based dispatch to clear demand and supply in its spot market. Power plants submit the technical characteristics of their units and natural gas or other input contracts with the input prices to the Load Economic Dispatch Center (CDEC), the Independent System Operator (ISO) in Chile. Based on this information, the CDEC computes daily unit-level start-up and variable operating costs and uses these costs, demand, and their network model to determine the least-cost dispatch under transmission constraints.

This cost-based dispatch mechanism differs from bid-based dispatch, 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. Wolak (2003) describes that, 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. Yet, 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.

We provide three pieces of evidence that firms were unlikely to exercise market power in the Chilean wholesale electricity market during our sample period. First, the cost-based dispatch system in Chile requires firms to submit all maintenance/outage schedules in advance to the system operator, and this information is made publicly available. Major maintenance has to be reported 30 days in advance and minor maintenance that takes less than 15 days has to be reported 15 days in advance. Therefore, it is difficult for firms to use maintenance/outages to exercise market power strategically.

Second, we investigate whether firms exercise market power by overstating the marginal costs of their units. Although their daily marginal costs are monitored and validated by the system operator, it could still be possible that firms with high market shares—dominant firms—overstate their marginal costs to increase the market clearing price. To test this possibility, we exploit the market integration in 2017. As we explained in Section 3, the two largest electricity markets (the SING and SIC) had been fully separated until they were integrated in 2017. This means dominant firms in each market would likely lose significant market shares when the SIC and SING were integrated into one market (the SEN). Indeed, our data indicate that Engie had a 33% market share in the SING, which changed to 8% in the SEN. AES Andes had a 47% market share in the SING, which changed to 27% in the SEN. BHP Billiton had a 5% market share in the SING, which changed to 3% in the SEN. Enel had a 34% market share in the SIC, which changed to 27% in the SEN. Colbun had a 23% market share in the SIC, which changed to 16% in the SEN.

The incentives to overstate marginal costs were substantially lowered after the market integration because of the increased competitiveness and decreased market shares. Therefore, if they exercised market power by overstating marginal costs, we would expect *declines* in marginal costs for their units.

We test this hypothesis in Figure A.7. By firm and generation type (coal or gas), we calculate the generation-weighted daily average of marginal costs during the month before and after the integration. Panels A and B show results for coal and natural gas plants, respectively. We do not find evidence of *declines* in marginal costs. For natural gas plants in Enel, we see an increase in marginal cost right before the integration, likely due to a change in its natural gas contract. However, the direction of the change (an increase in marginal costs) is not consistent with a prediction from the possible market power. Therefore, this figure suggests that dominant firms were unlikely to overstate marginal costs in order to increase the market clearing price.

Third, while it is not possible for firms to use planned maintenance/outages to exercise market power, there is a possibility that they use unplanned maintenance/outages to do so, although that can be also almost impossible because of close monitoring from the regulator. To investigate the issue of unplanned maintenance/outages, we provide the following analysis.

Consider hours in which the hourly marginal cost is below the hourly node price. If there is no startup cost, competitive firms should produce nearly 100% of the time in this situation. In reality, there is a startup cost, so we expect that this number is less than 100% on some days. For each hour at the firm level, we calculate the ratio of power plants that produce if the hourly node price is above the marginal cost.

Our hypothesis is that if large firms exercise market power by unplanned outages, we should observe an *increase* in this ratio after the market integration. In Panel A of Figure A.8, we show the results for the largest four firms. For each unit at the hourly level, we define a dummy variable of availability, which equals one if the unit produces if the hourly node price is above the marginal cost and equals zero if it does not produce even if the hourly node price is above the marginal cost. In Panel A, we show the average of this variable at the firm level for each hour for the largest four firms.

We do not find a statistically significant increase in this ratio for each firm. One firm, ENEL, had a decline in this ratio and, therefore, we investigated the reason. We found that one plant owned by ENEL (TER Tarapaca) had a scheduled repair, which was required to report 30 days in advance in 2017. In Panel B of Figure A.8, we plot ENEL's results at the plant level to confirm this point.

Overall, we do not find statistical evidence of strategic unplanned outages in our sample period. This is likely because both planned and unplanned outages are closely monitored by the system operator in the Chilean market.

APPENDIX D: INVESTMENT EFFECTS ON THERMAL POWER PLANTS

It is important to note that 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 transmission expansion.

In Figure A.9, we examine thermal plants' entry and potential exit. In Panel A, 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.

Measuring thermal plant exit in our data is not as straightforward as with entry. Our analysis considers plants no longer available if they stop submitting daily costs to the system operator to be dispatched.[55]

In Panel B of Figure A.9, we present thermal plants' cumulative "potential" exit. We consider that a unit potentially exited if it no longer offers its capacity to the system operator and does not produce for at least a year. For these units, we use the last time with submitted bids as the exit time and use unit-level capacity (MW) to show cumulative exit in MW. Although exit appears to be exacerbated after the renewable expansion starts, we observe modest exit of plants, in the order of 344 MW of capacity, relative to the total installed thermal capacity, which was over 15 GW during our main period of study.[56] Interestingly, some exits seem to align quite well with the events. While not in our current counterfactuals, one could bound the impact of these exits by attributing them to the transmission expansion. However, the impacts are expected to be small given the size of the plants.

APPENDIX E: ESTIMATING A CORRECTED EVENT STUDY

Our theory in Section 2 and empirical findings in Section 5.3 suggest that the conventional event study estimation is likely to underestimate the cost savings from market integration because it does not account for potential investment effects. In this subsection, we explore how to correct such bias in the event-study framework.

The challenge in the event study approach is that it cannot correctly capture investment effects if investment occurs in anticipation of the events. How can we address this problem? Our idea is based on the following thought experiment: What would happen to our regression estimates if investment were coincidental to the transmission expansion, as opposed to anticipated?

To implement an event-study estimation with investment effects, we take two steps. First, we use our structural model to compute how much of the observed solar investments would have been unprofitable in counterfactual scenarios as we did in Section 5.3.

[55] In practice, some of those power plants could be potentially brought back to the market, that is, they could be reopened after a period of "mothballing."

[56] As an alternative definition of exit, we also attempted to focus on plants with zero production during long periods. However, this is problematic because (1) having long periods of zero production is not uncommon for the very expensive peaker plants, and (2) the plants are still available in our analysis for calculating the nationwide merit order and our counterfactuals, therefore, their capacity *can be used*, even if the plants are irrelevant in practice.

We compute thresholds for both a scenario with only the interconnection, and one with no expansion. In the absence of interconnection and reinforcement, 80% of the observed solar in Antofagasta and 83% in Atacama would have been unprofitable. If the interconnection was built but the reinforcement was not, 50% of the observed solar in Antofagasta and 70% in Atacama would have been unprofitable. This implies that without anticipatory investments, we would have 20% of the observed solar in Antofagasta and 17% in Atacama in the pre-interconnection period, 50% of the observed solar in Antofagasta and 30% in Atacama in the period after the interconnection and before the reinforcement, and 100% of the observed solar in both zones after the reinforcement. The structural model also provides us the market equilibrium production quantities, prices, and costs with different levels of investment.

Second, we use these three scenarios to construct a simulated time series in which investment changes occur at the same time at the event. We use the time series with only 20% of solar investment in Antofagasta and 17% in Atacama for the period before the interconnection; we use the time series with 50% of solar investment in Antofagasta and 30% in Atacama for the interim period, and we set investment to 100% for both zones when the reinforcement occurs. We use the equilibrium outcomes from this new time series, corrected by changes in investment, to estimate the event-study regression in equation (1). This implies that our time series, by construction, has structural investment breaks right at the moment in which our two-event studies occur.

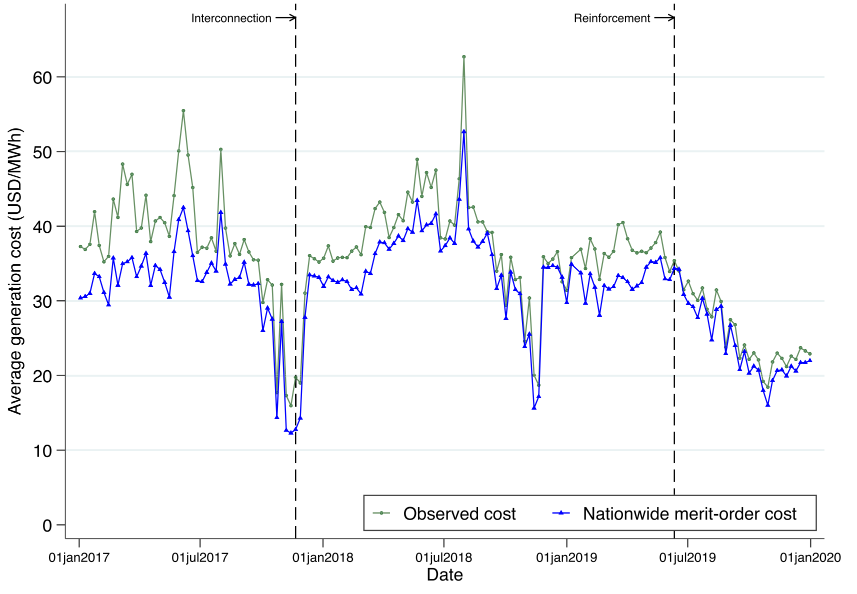
In Table A.VII, we present the event-study regressions with and without investment effects. To make the comparison easier, we present only the coefficients on the interconnection and reinforcement dummy variables in this table. Still, the regressions include the same set of control variables as in column 4 of Table 2. We use the first three columns to present results for hour 12 and the last three columns to show results for all hours.

In columns 1–3, we estimate the conventional event-study regression without investment effects. Because the anticipatory investment in solar plants occurred well before the events, this method underestimates the benefit of transmission expansions. Columns 1 and 2 indicate that costs are reduced by 0.80 and 1.90 \$/MWh at noon (hour 12) thanks to the interconnection and reinforcement, respectively. In columns 4–6, we estimate the event study regression with investment effects and find that the cost savings from the interconnection and reinforcement are 0.98 and 5.95 \$/MWh at noon. Comparison between columns 3 and 6 suggests that accounting for the investment benefits of the lines substantially increases the estimates of cost reductions. This highlights some of the added benefits that might be underestimated by a more naïve event-study design.

Note that in columns 4–6, we use our structural model to compute the market equilibrium, create time-series data based on this result, and estimate the event-study regression in equation (1). We take this approach on purpose to compare how the standard event-study results differ from the event-study results with investment effects. In columns 7–9, we present results from counterfactual simulations to compare them with results from the event-study estimation. To estimate the impact of the interconnection and reinforcement by counterfactual simulation, we run the same event-study regressions, but excluding the out-of-merit cost, with dependent variable being the *cost difference* between actual scenario and the counterfactual scenario with investment effects. Comparison between columns 6 and 9 suggest that once we include investment effects, the event-study estimation, which identifies the event impacts based on before-and-after data, and the simulation approach, which identifies the event impacts based on cost difference between the two counterfactuals, produce numerically similar results.

APPENDIX F: APPENDIX FIGURES AND TABLES

Panel A: Hour 12



Panel B: All hours

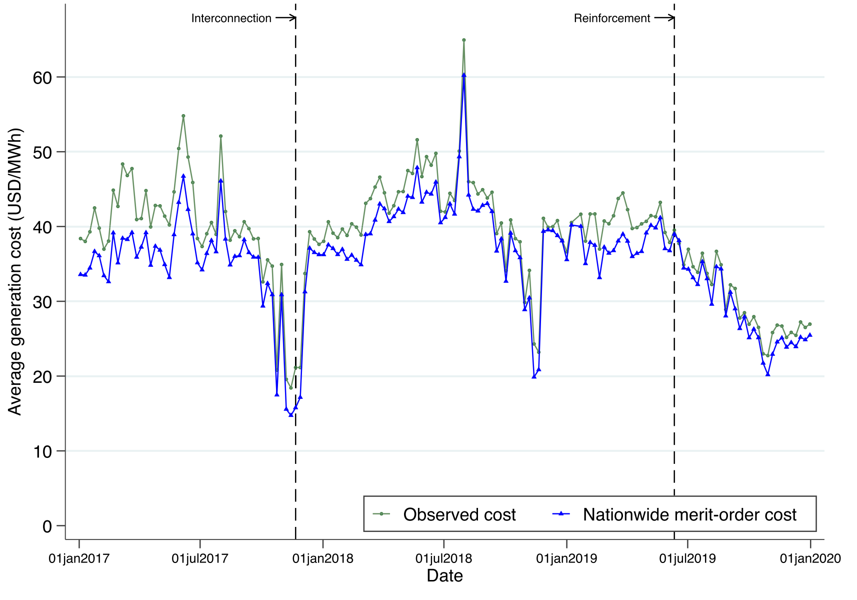
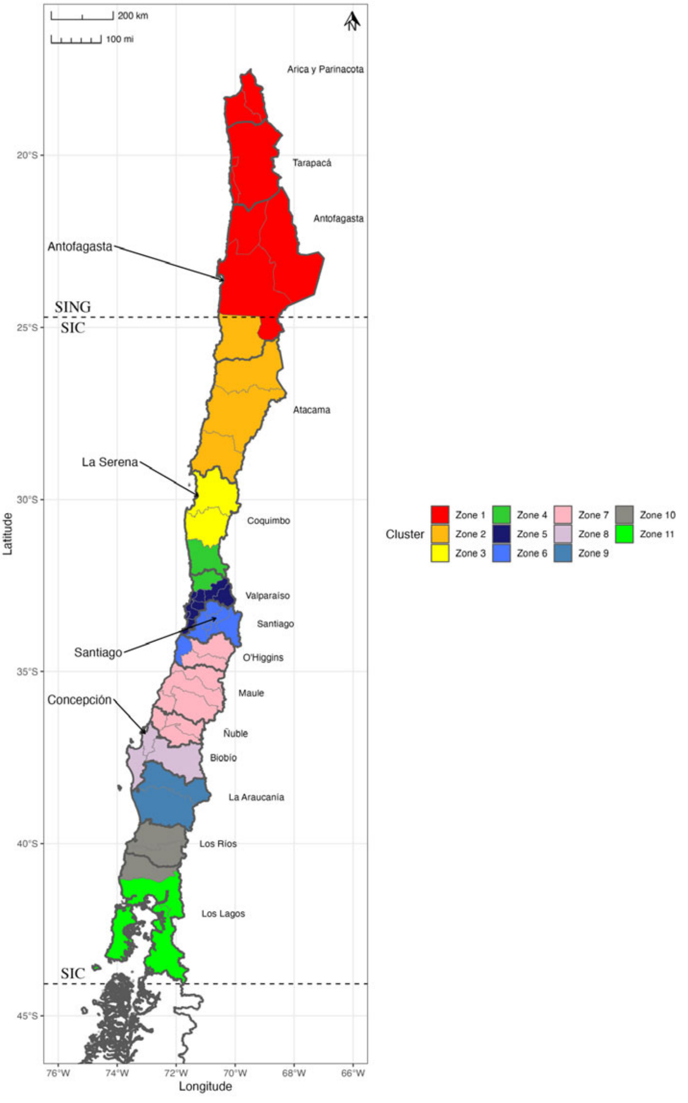


FIGURE A.1.—Observed generation cost and nationwide merit-order cost. *Note*: This figure shows the observed system-level generation cost per MWh and the nationwide merit-order cost (the minimum possible generation cost per MWh with full trade), which are relevant to equation (1).

Panel A: A map of Chile



Panel B: Mapping between regions in Chile and zones.

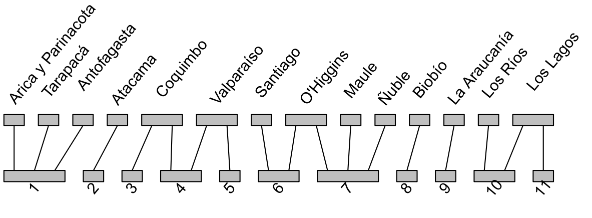
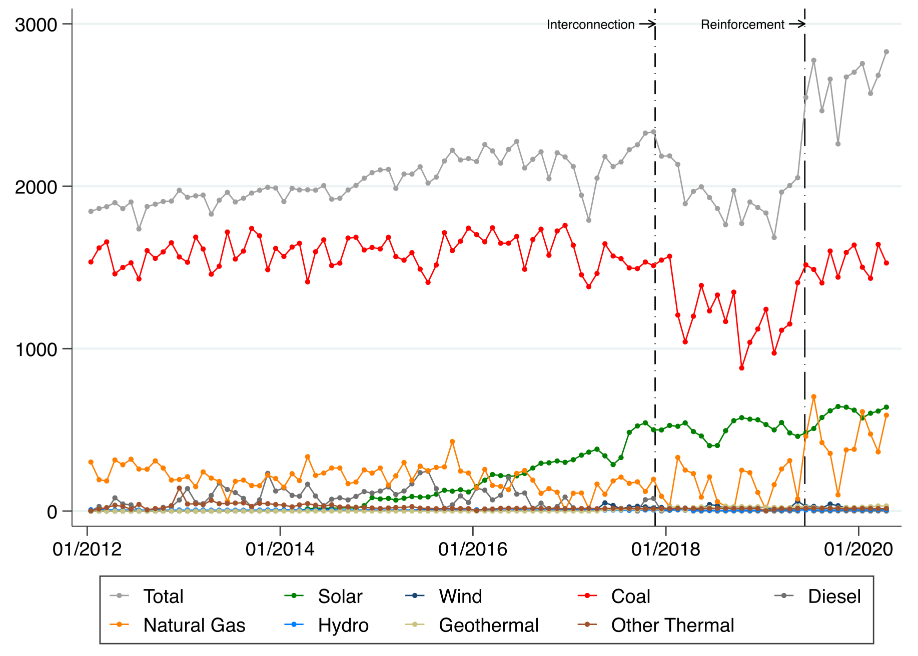


FIGURE A.2.—Map of zones. *Note*: Panel A shows how we divide Chile into 11 zones. Panel B shows the mapping between regions in Chile and zones.

Panel A: SING (north)



Panel B: SIC (south)

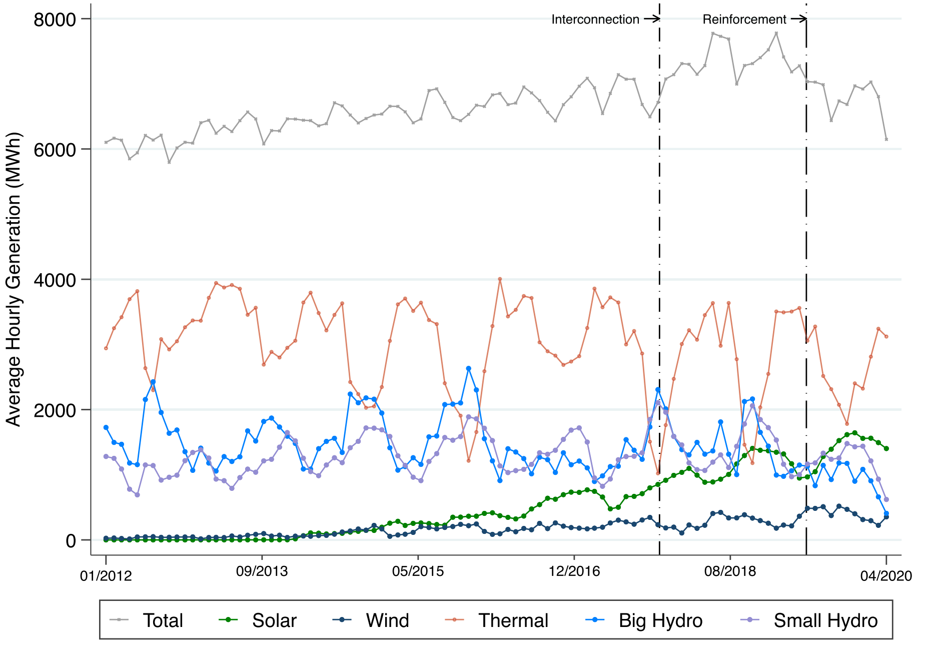


FIGURE A.3.—Impacts of market integration on electricity generation by fuel type. *Note*: This figure shows the average daily generation (MWh) by fuel type over the calendar months.

Panel A: Zone 1

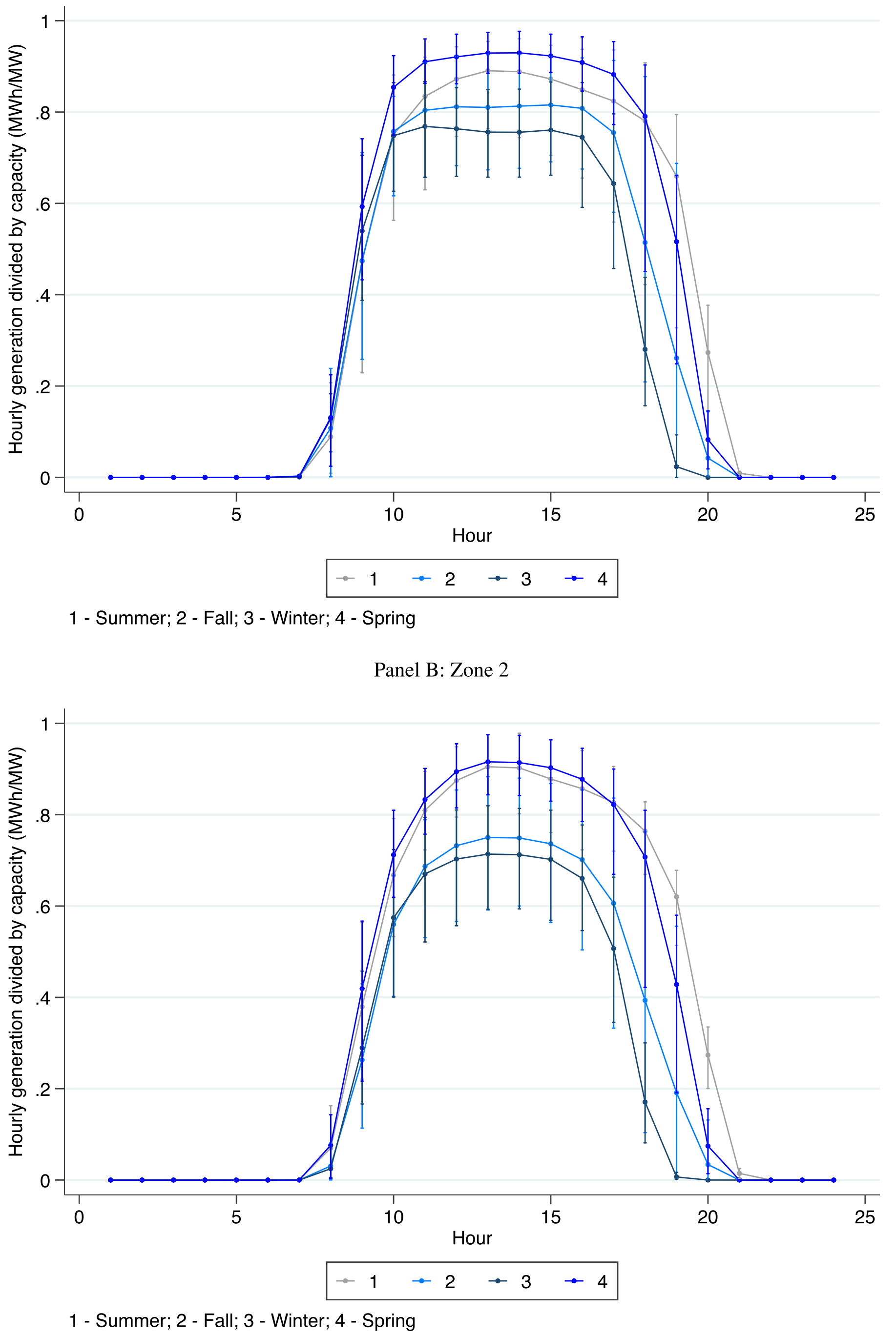


FIGURE A.4.—Solar potential in zones 1 and 2: 10 and 90 percentile of capacity factor in 2019. *Note*: We plot the distribution of solar capacity factor in 2019 for zones 1 and 2, defined as the ratio between hourly solar generation (in MWh) and solar capacity (in MW), by season and by hour of the day. The upper end of each bar is the 90th percentile and the lower end of each bar is the 10th percentile.

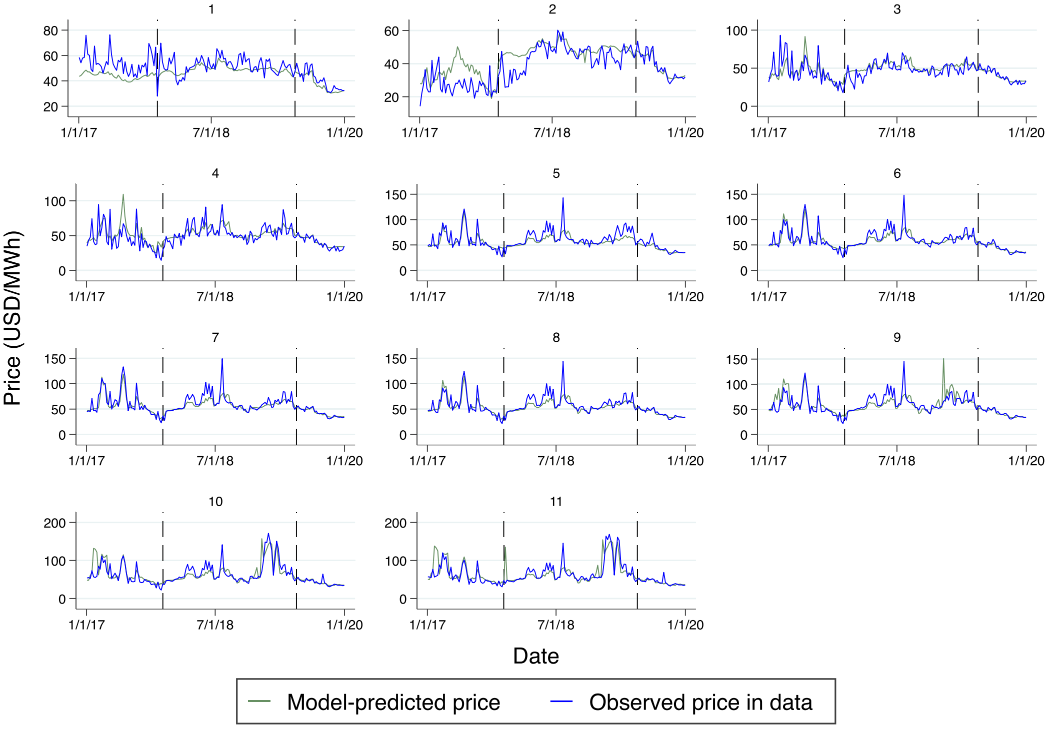


FIGURE A.5.—Zone-level price fit. *Note*: We show how the model-predicted price fits the observed price for each zone. For each zone, we plot weekly generation-weighted average price.

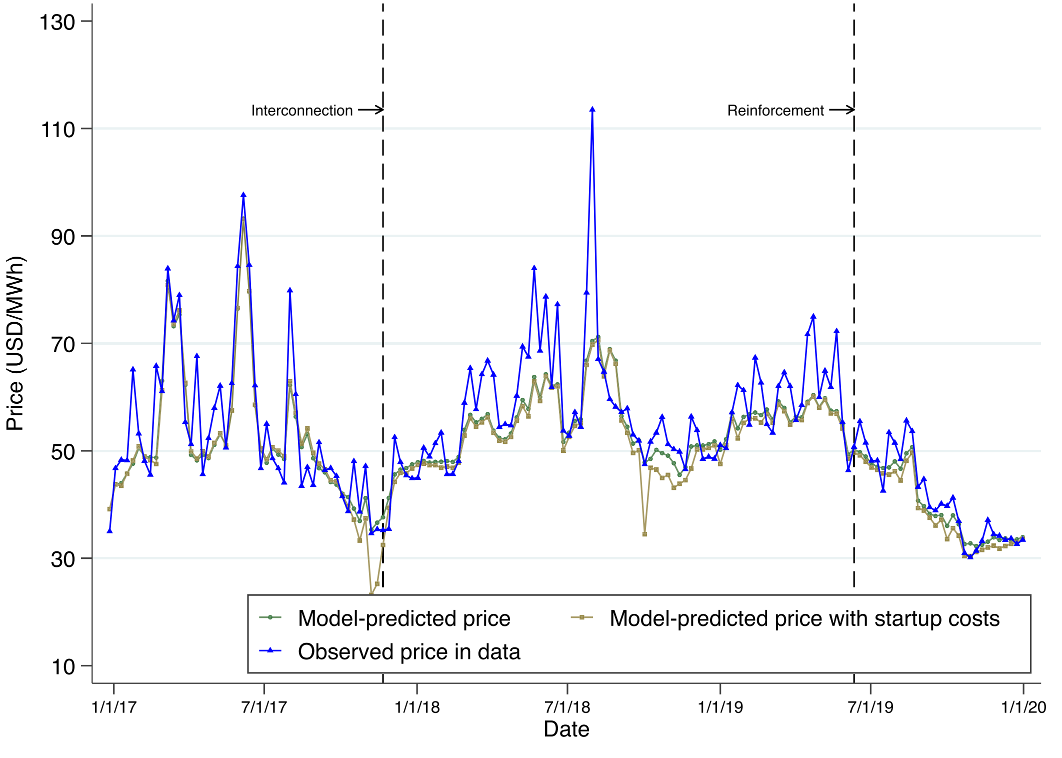
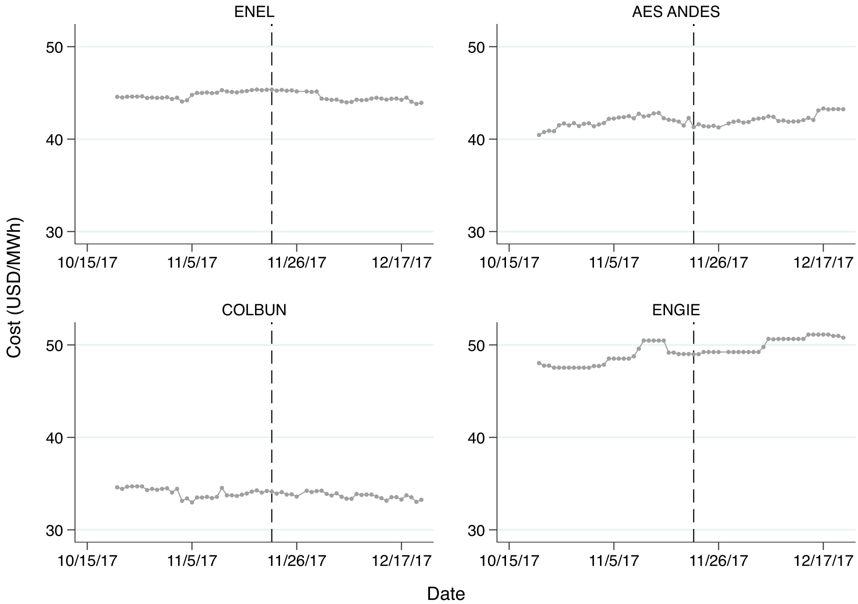


FIGURE A.6.—Price fit with and without startup costs. *Note*: We compare the price predicted by our baseline model and the model with startup costs.

Panel A: Coal power plants



Panel B: Gas power plants

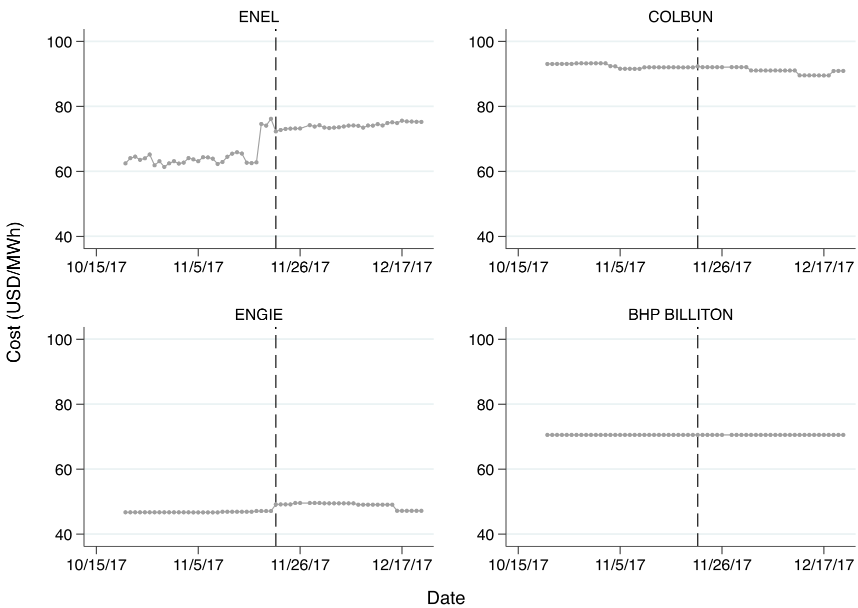
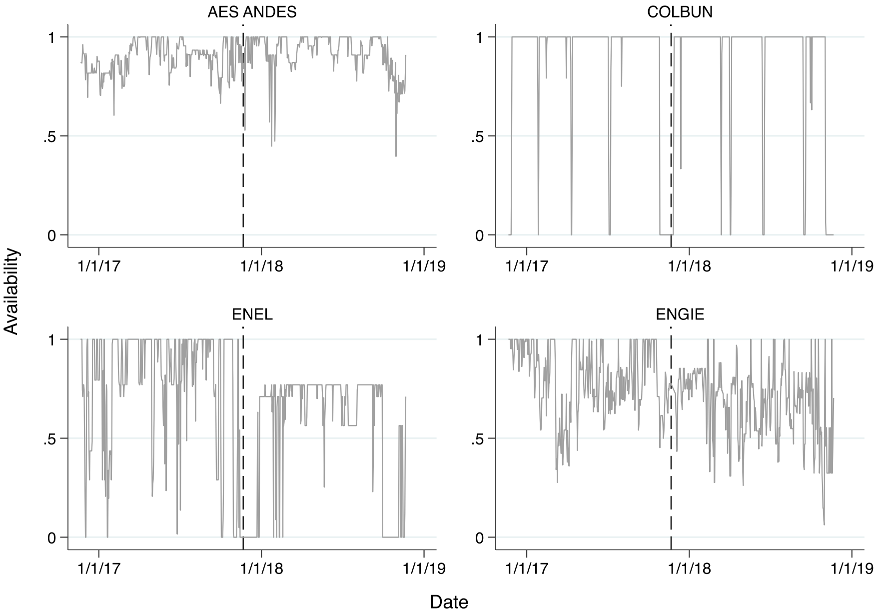


FIGURE A.7.—Analysis of market power in the cost-based dispatch (marginal cost). *Note*: By firm and generation type (coal or gas), we calculate the generation-weighted daily average of marginal costs during a month before and a month after the integration. The figure suggests that we do not find evidence of *declines* in marginal costs when the SIC and SING were integrated into the SEN in November 2017. Note that Engie had a 33% market share in the SING, which changed to 8% in the SEN. AES Andes had a 47% market share in the SING, which changed to 27% in the SEN. BHP Billiton had a 5% market share in the SING, which changed to 3% in the SEN. Enel had a 34% market share in the SIC, which changed to 27% in the SEN. Colbun had a 23% market share in the SIC, which changed to 16% in the SEN.

Panel A: Four largest firms' coal plants



Panel B: Generators owned by ENEL

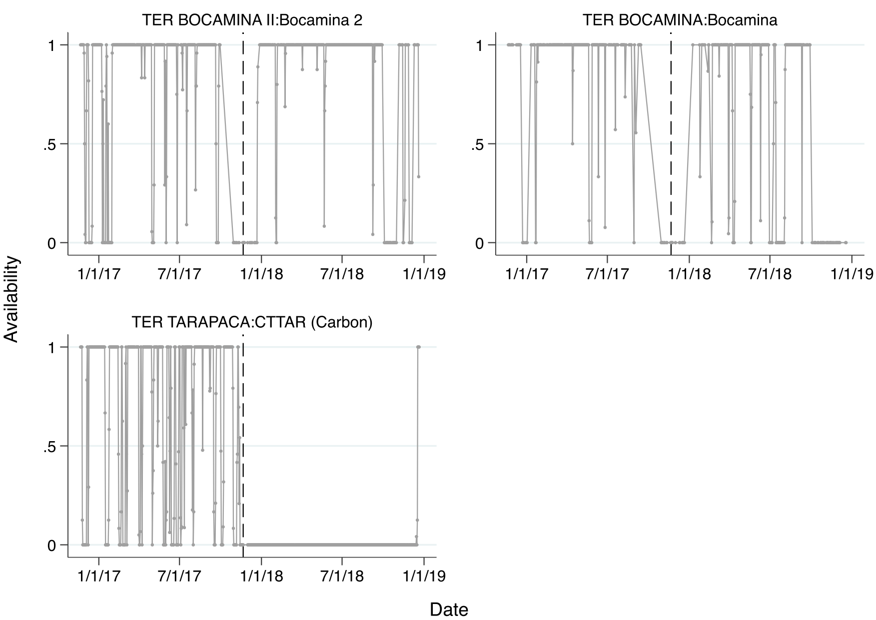
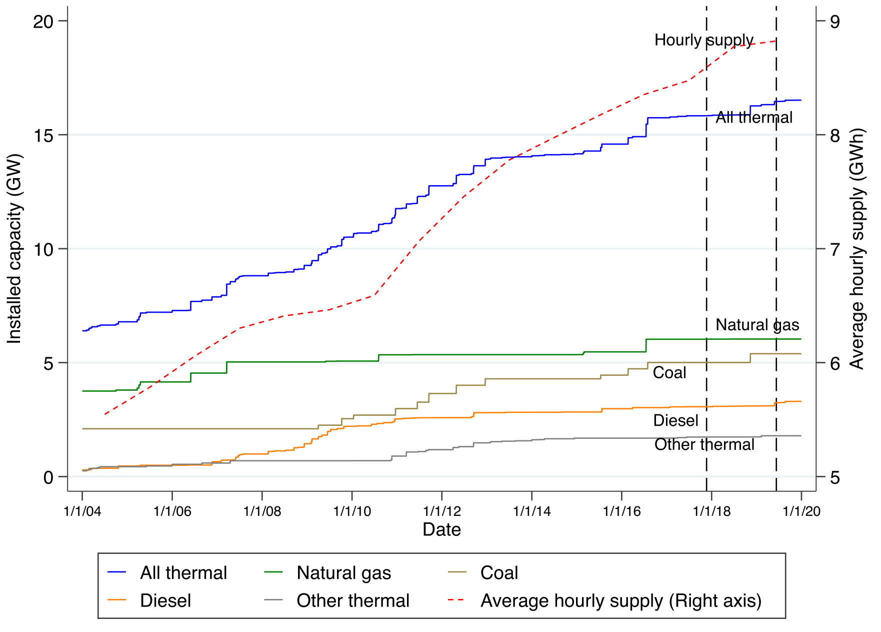


FIGURE A.8.—Analysis of market power in the cost-based dispatch (unit availability). *Note*: For each unit at the hourly level, we define a dummy variable of availability, which equals 1 if the unit produces when the hourly node price is above the marginal cost and equals 0 if it does not produce even if the hourly node price is above the marginal cost. In Panel A, we show the average of this variable at the firm level for each hour for the largest four firms. The reason why ENEL had a decline in this variable in 2018 was that one plant owned by ENEL (TER Tarapaca) had a scheduled repair, which was reported 30 days in advance in 2017. In Panel B, we plot ENEL's results at the plant level to confirm this point.

Panel A: Entry



Panel B: Potential exit

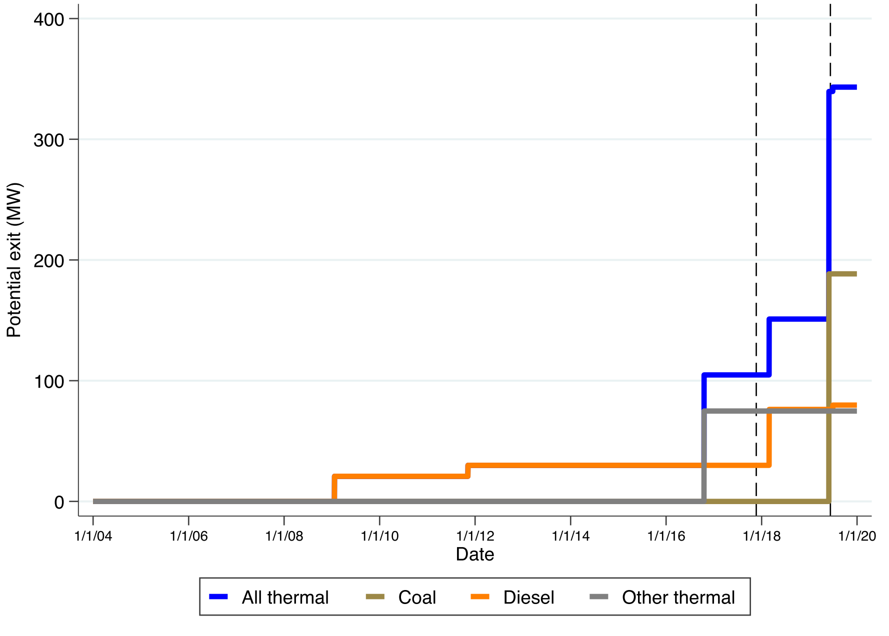


FIGURE A.9.—Entry and potential exist of thermal plants. *Note*: Panel A shows the cumulative entry of thermal plants. We use the first time of positive production to define unit-level entry and use unit-level capacity (MW) to show the cumulative entry in MW. Panel B shows the cumulative "potential" exit of thermal plants. We consider that a unit potentially exited if the unit does no longer offer its capacity to the system operator and do not produce at least for a year. For these units, we use the last time with submitted bids as the time of exit and use unit-level capacity (MW) to show cumulative exit in MW.

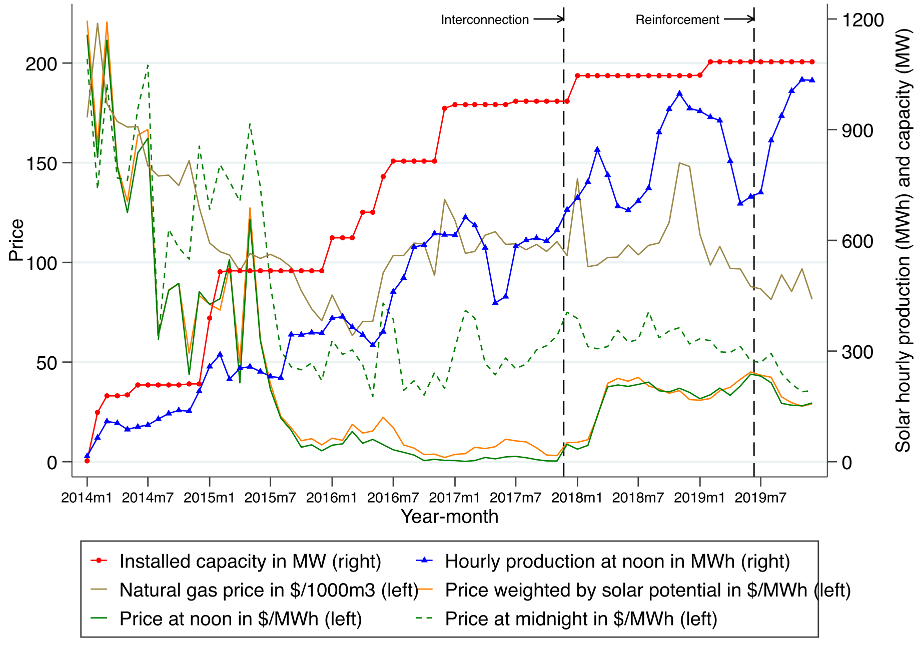


FIGURE A.10.—Figure 4 of the main text, with international commodity prices. *Note*: This figure is Figure 6 in the main text, with two additional lines. We first include the international price of natural gas (Henry Hub price). We also include the monthly average price (in zone 2) weighted by the solar potential. We calculate a weight for each hour-of-day based on the average hourly solar production in 2019; we then calculate the average price for each month in zone 2 based on these weights.

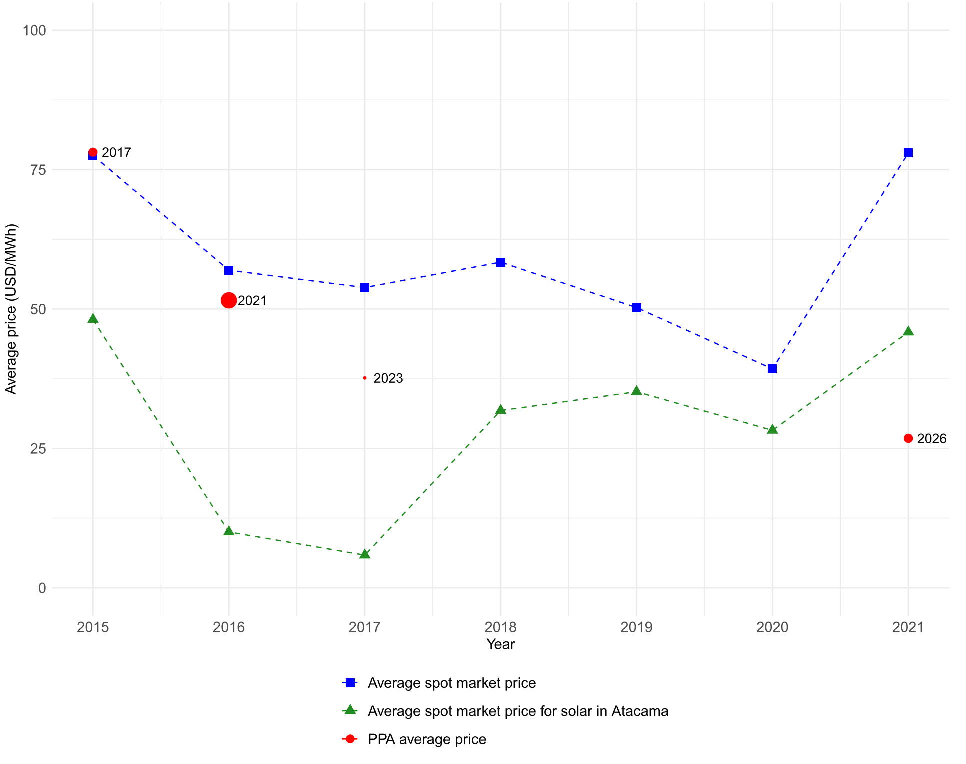


FIGURE A.11.—Average prices of a subset of the Power Purchase Agreements (PPA). *Note*: A subset of the power purchase agreements for the regulated customers (i.e., customers with less than 500 kW) are publicly available on the website of Licitaciones Eléctricas. Note that this data set does not include bilateral contracts for customers with over 500 kW. Each dot represents the average price of the PPA for firms that have solar plants in Atacama. Note that data available from the PPA is at the firm level rather than the plant level and, therefore, we need to make a few assumptions to calculate the average price for each region, as we described in the main text of the paper. The number next to each dot is the start year of contracts, and the size of the dots correspond to the quantity contracted. As a reference, we also show the system-level average spot market prices (weighted by generation) and the average spot market prices for solar plants in the Atacama region (weighted by generation).

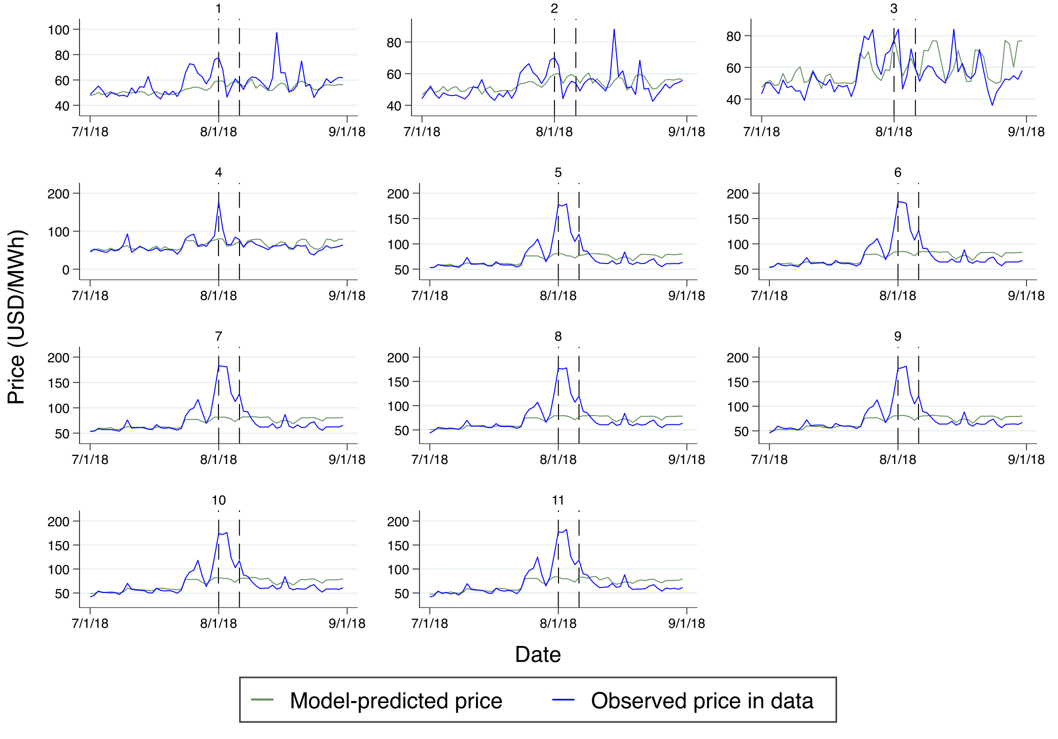


FIGURE A.12.—Model fit in July–August 2018. *Note*: This figure plots the model-predicted daily price and observed price for each zone from 7/1/2018 to 8/31/2018.

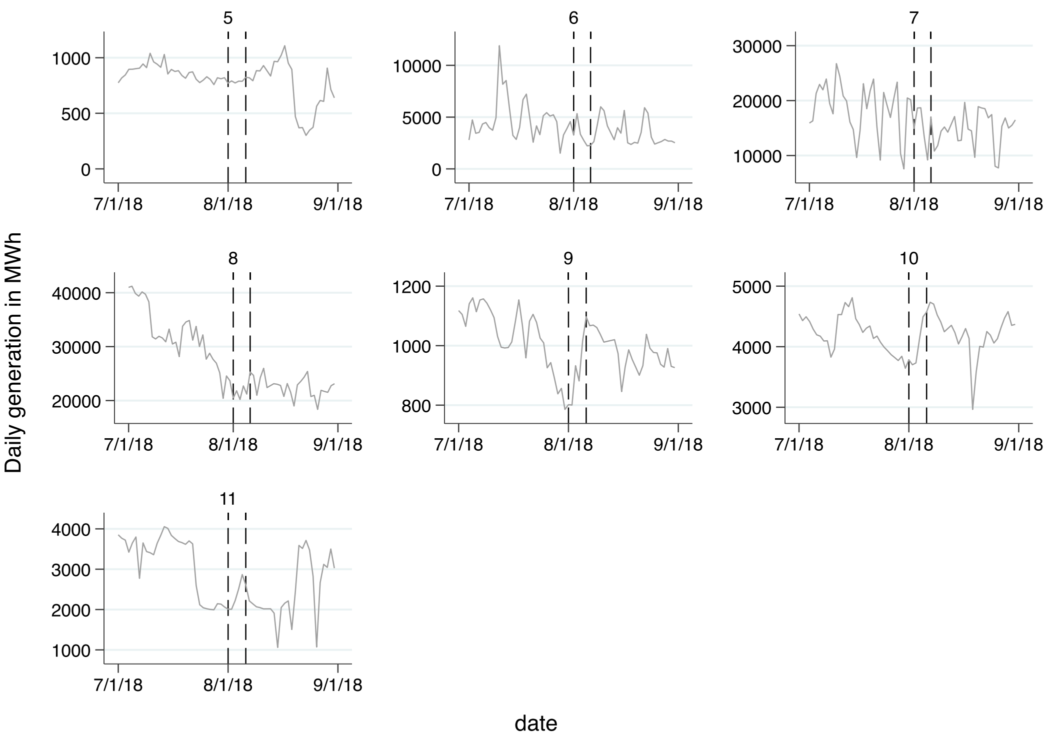


FIGURE A.13.—Daily hydro production: Zones 5–11. *Note*: This figure plots daily hydro production at the zone level for zones 5–11 from 7/1/2018 to 8/31/2018.

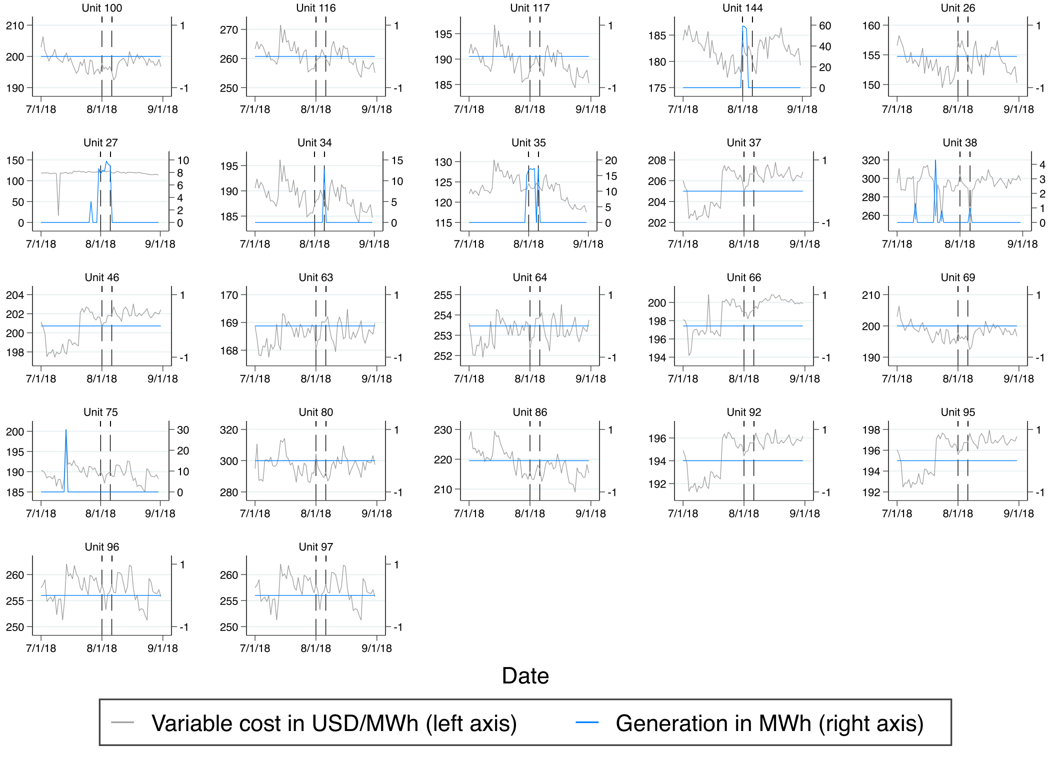


FIGURE A.14.—Variable cost and hourly production of diesel units: Example of hour 17. *Note*: This figure plots the variable cost and hourly generation for diesel units in zones 5–7 in hour 17 (6 p.m.–7 p.m.) from 7/1/2018 to 8/31/2018.

TABLE A.I

SUMMARY STATISTICS WITH SIC AND SING DECOMPOSITION IN THE POST-INTERCONNECTION PERIOD.

	Pre-Interconnection (Nov. 2016–Nov. 2017)		Post-Interconnection (Nov. 2017–Dec. 2019)		
	SIC	SING	SIC	SING	SEN
Hourly total generation at noon (MWh)	6851	2135	7241	2108	9349
	(645)	(186)	(693)	(406)	(647)
Hourly total generation at midnight (MWh)	5900	2241	6075	2407	8482
	(316)	(195)	(386)	(257)	(351)
Node price at noon (USD/MWh)	54.46	45.14	55.85	39.45	52.16
	(35.58)	(16.95)	(26.68)	(10.85)	(25.01)
Node price at midnight (USD/MWh)	52.06	71.66	54.05	56.78	54.82
	(24.9)	(35.26)	(20.52)	(21.85)	(20.94)
Variable cost: Thermal (USD/MWh)	44.67	42.94	43.92	43.45	43.73
	(17.28)	(11.12)	(16.3)	(13)	(15.08)
Installed capacity (*MW*)					
Hydro	6225	16	6288	16	6304
Solar	1315	603	1805	695	2500
Thermal	6131	3832	6177	4208	10385
Wind	1144	194	1815	194	2009

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

TABLE A.II

TRADE CAPACITY.

	Period 1	Period 2	Period 3
Line 1	0.00	570.68	816.87
Line 2	339.75	586.97	1601.96
Line 3	344.15	580.82	1711.40
Line 4	383.44	609.60	1772.79
Line 5	1870.97	1989.78	2737.05
Line 6	1942.99	2059.91	2059.91
Line 7	1502.85	1602.19	1602.19
Line 8	304.43	365.02	365.02
Line 9	217.69	217.69	217.69
Line 10	115.57	116.15	133.29

Note: This table shows the transmission capacity used in our structural model described in Section 5. “Period 1” is January 1, 2017, to November 20, 2017 (before interconnection); “Period 2” is November 21, 2017, to June 10, 2019 (after interconnection, before reinforcement); “Period 3” is June 11, 2019, to December 31, 2019 (after reinforcement).

TABLE A.III

GENERATION RATIO.

	Renewable	Hydro	Coal	Natural gas	Other thermal	Total
Pre-interconnection						
Observed	9.9%	26.8%	39.8%	18.8%	4.7%	100.0%
Model-predicted	11.1%	26.7%	39.6%	18.4%	4.2%	100.0%
Post-interconnection, Pre-reinforcement						
Observed	12.4%	29.7%	37.4%	16.4%	4.2%	100.0%
Model-predicted	12.9%	29.5%	38.7%	15.1%	3.8%	100.0%
Post-reinforcement						
Observed	16.1%	28.5%	36.6%	15.8%	3.1%	100.0%
Model-predicted	16.4%	28.8%	40.1%	11.9%	2.8%	100.0%

Note: This table shows the goodness-of-fit of our structural model described in Section 5.1.

TABLE A.IV

AN ALTERNATIVE DEPENDENT VARIABLE TO THE EVENT STUDY ANALYSIS OF THE IMPACT OF MARKET INTEGRATION.

Dependent Variable: Generation Cost Minus Nationwide Merit-Order Cost (USD/MWh)								
	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	−2.63	−2.60	−2.62	−2.63	−2.12	−2.14	−2.14	−2.05
	(0.20)	(0.27)	(0.27)	(0.27)	(0.14)	(0.17)	(0.17)	(0.17)
1(After the reinforcement)	−1.92	−1.23	−1.38	−1.18	−1.19	−0.66	−0.66	−0.69
	(0.13)	(0.55)	(0.58)	(0.60)	(0.09)	(0.35)	(0.36)	(0.37)
Coal price [USD/ton]		−0.01	−0.01	−0.01		−0.01	−0.01	−0.00
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			−7.89	−7.88			0.08	0.16
			(3.98)	(3.94)			(3.04)	(2.99)
Hydro availability				0.25				−0.00
				(0.15)				(0.00)
Scheduled demand (GWh)				−0.12				−0.01
				(0.13)				(0.00)
Sum of effects	−4.55	−3.82	−4.00	−3.81	−3.31	−2.79	−2.79	−2.74
Mean of dependent variable	3.94	3.94	3.94	3.94	3.09	3.09	3.09	3.09
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.31	0.49	0.49	0.49	0.35	0.57	0.57	0.57

Note: In our main analysis in Table 2, we use the generation cost (USD/MWh) as a dependent variable and the nationwide merit-order cost (i.e., the least possible generation cost that can be obtained without any trade constraints) as a control variable. In this table, we use the difference between the generation cost and nationwide merit-order cost as a dependent variable. The coefficients for the interconnection and reinforcement are very similar to the ones in Table 2.

TABLE A.V

AN ALTERNATIVE CONTROL TO THE EVENT STUDY ANALYSIS OF THE IMPACT OF MARKET INTEGRATION.

Dependent Variable: Generation Cost (USD/MWh)								
	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	−2.78	−3.32	−3.37	−3.27	−2.11	−2.60	−2.61	−2.52
	(0.16)	(0.24)	(0.23)	(0.22)	(0.12)	(0.15)	(0.15)	(0.15)
1(After the reinforcement)	−2.28	−0.49	−0.79	0.12	−1.47	0.09	0.04	0.25
	(0.20)	(0.47)	(0.50)	(0.46)	(0.13)	(0.31)	(0.32)	(0.31)
Minimum dispatch cost with no market integration	0.98	0.96	0.96	1.01	0.98	0.97	0.97	0.99
	(0.01)	(0.02)	(0.02)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		0.02	0.03	0.02		0.02	0.03	0.02
		(0.01)	(0.01)	(0.01)		(0.01)	(0.01)	(0.01)
Natural gas price [USD/m^3]			−15.21	−16.27			−2.86	−3.77
			(4.69)	(4.66)			(2.98)	(2.99)
Hydro availability				1.06				0.02
				(0.13)				(0.00)
Scheduled demand (GWh)				−0.96				−0.03
				(0.13)				(0.00)
Sum of effects	−5.06	−3.82	−4.15	−3.15	−3.58	−2.51	−2.57	−2.27
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	0.93	0.95	0.95	0.95	0.96	0.97	0.97	0.97

Note: In our main analysis in Table 2, we use the nationwide merit-order cost (i.e., the least possible generation cost that can be obtained without any trade constraints) as a control variable. In this table, we use 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) as a control variable.

TABLE A.VI

EVENT STUDY ANALYSIS WITH AND WITHOUT INVESTMENT EFFECTS.

Panel A: Without investment effects								
	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	−1.35	−0.70	−0.73	−0.80	−0.76	−0.36	−0.37	−0.41
	(0.13)	(0.13)	(0.13)	(0.13)	(0.08)	(0.08)	(0.08)	(0.07)
1(After the reinforcement)	0.02	−1.30	−1.48	−1.90	−0.07	−0.93	−0.98	−1.10
	(0.10)	(0.25)	(0.26)	(0.29)	(0.05)	(0.14)	(0.14)	(0.15)
Nationwide merit-order cost	1.10	1.13	1.13	1.11	1.04	1.05	1.05	1.03
	(0.01)	(0.01)	(0.01)	(0.02)	(0.01)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		−0.04	−0.04	−0.04		−0.03	−0.03	−0.03
		(0.01)	(0.01)	(0.01)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			−9.29	−8.94			−2.57	−2.12
			(2.31)	(2.23)			(1.13)	(1.08)
Hydro availability				−0.50				−0.01
				(0.07)				(0.00)
Scheduled demand (GWh)				0.49				0.02
				(0.07)				(0.00)
Sum of effects	−1.34	−2.00	−2.21	−2.70	−0.83	−1.29	−1.35	−1.51
Mean of dependent variable	32.69	32.69	32.69	32.69	36.10	36.10	36.10	36.10
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.97	0.98	0.98	0.98	0.99	0.99	0.99	0.99

(*Continues*)

TABLE A.VI

Continued.

Panel B: With investment effects								
	Hour 12				All hours			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1(After the interconnection)	−1.52	−1.03	−1.03	−0.97	−0.83	−0.58	−0.57	−0.58
	(0.13)	(0.13)	(0.13)	(0.14)	(0.08)	(0.08)	(0.08)	(0.08)
1(After the reinforcement)	−4.69	−5.55	−5.56	−5.95	−2.06	−2.61	−2.58	−2.65
	(0.10)	(0.26)	(0.27)	(0.30)	(0.05)	(0.14)	(0.15)	(0.15)
Nationwide merit-order cost	1.07	1.13	1.13	1.13	1.02	1.05	1.05	1.04
	(0.01)	(0.01)	(0.01)	(0.02)	(0.00)	(0.01)	(0.01)	(0.01)
Coal price [USD/ton]		−0.04	−0.04	−0.04		−0.02	−0.03	−0.02
		(0.01)	(0.01)	(0.01)		(0.00)	(0.00)	(0.00)
Natural gas price [USD/m^3]			−0.62	−0.58			1.64	1.89
			(2.17)	(2.06)			(1.04)	(1.06)
Hydro availability				−0.48				−0.01
				(0.07)				(0.00)
Scheduled demand (GWh)				0.01				0.01
				(0.07)				(0.00)
Sum of effects	−6.22	−6.58	−6.60	−6.92	−2.88	−3.19	−3.15	−3.23
Mean of dependent variable	36.36	36.36	36.36	36.36	37.60	37.60	37.60	37.60
Month FE	No	Yes	Yes	Yes	No	Yes	Yes	Yes
Sample size	1033	1033	1033	1033	1033	1033	1033	1033
R^2	0.98	0.98	0.98	0.98	0.99	0.99	0.99	0.99

Note: This table shows results under two sets of event study regressions described in equation (1). In Panel A, the dependent variable is the system-level average generation cost based on model simulation without investment effects. In Panel B, the dependent variable is the system-level average generation cost based on model simulation with investment effects. We shift the timing of solar investment so that it occurs right after the interconnection and reinforcement (i.e., correct for anticipatory investment effects), use our structural model to obtain market outcomes, and rerun the event study analysis (i.e., there is 20% solar investment left in zone 1 and 17% solar investment left in zone 2 without market integration; there is 50% solar investment left in zone 1 and 30% left in zone 2 with interconnection but without reinforcement; there is 100% solar investment in zones 1 and 2 after reinforcement).

TABLE A.VII

INVESTMENT EFFECTS FOR THE EVENT STUDY ANALYSIS.

	Model Cost Excluding Investment Effects			Model Cost With Investment Effects			Difference in Model Cost With Investment Effects		
	Inter.	Rein.	**Sum**	Inter.	Rein.	**Sum**	Inter.	Rein.	**Sum**
Hr 0	−0.11 (0.04)	−0.60 (0.09)	**−0.71**	−0.11 (0.04)	−0.61 (0.09)	**−0.72**	−0.34 (0.02)	0.25 (0.06)	**−0.10**
Hr 1	−0.11 (0.04)	−0.39 (0.09)	**−0.49**	−0.11 (0.04)	−0.40 (0.09)	**−0.51**	−0.32 (0.02)	0.23 (0.06)	**−0.09**
Hr 2	−0.13 (0.04)	−0.19 (0.09)	**−0.32**	−0.14 (0.04)	−0.21 (0.09)	**−0.35**	−0.30 (0.02)	0.22 (0.06)	**−0.08**
Hr 3	−0.13 (0.04)	−0.09 (0.09)	**−0.22**	−0.13 (0.04)	−0.11 (0.09)	**−0.24**	−0.28 (0.02)	0.21 (0.06)	**−0.07**
Hr 4	−0.13 (0.04)	−0.08 (0.09)	**−0.21**	−0.13 (0.04)	−0.10 (0.09)	**−0.23**	−0.28 (0.02)	0.21 (0.06)	**−0.07**
Hr 5	−0.12 (0.04)	−0.19 (0.09)	**−0.31**	−0.13 (0.04)	−0.20 (0.09)	**−0.33**	−0.28 (0.02)	0.22 (0.06)	**−0.06**
Hr 6	−0.12 (0.04)	−0.44 (0.09)	**−0.56**	−0.09 (0.04)	−0.44 (0.09)	**−0.53**	−0.29 (0.02)	0.23 (0.06)	**−0.06**
Hr 7	−0.16 (0.04)	−0.91 (0.09)	**−1.07**	−0.08 (0.04)	−1.29 (0.09)	**−1.37**	−0.48 (0.02)	−0.16 (0.06)	**−0.65**
Hr 8	−0.07 (0.04)	−1.49 (0.09)	**−1.56**	−0.56 (0.04)	−3.71 (0.09)	**−4.27**	−1.38 (0.02)	−1.62 (0.06)	**−2.99**
Hr 9	−0.21 (0.04)	−1.84 (0.09)	**−2.05**	−0.91 (0.04)	−5.37 (0.09)	**−6.28**	−1.94 (0.02)	−2.87 (0.06)	**−4.81**
Hr 10	−0.43 (0.04)	−1.97 (0.09)	**−2.39**	−0.94 (0.04)	−5.85 (0.09)	**−6.78**	−2.07 (0.02)	−3.20 (0.06)	**−5.27**
Hr 11	−0.67 (0.04)	−1.91 (0.09)	**−2.58**	−0.96 (0.04)	−5.92 (0.09)	**−6.88**	−2.11 (0.02)	−3.33 (0.06)	**−5.44**
Hr 12	−0.80 (0.04)	−1.90 (0.09)	**−2.70**	−0.97 (0.04)	−5.95 (0.09)	**−6.92**	−2.12 (0.02)	−3.43 (0.06)	**−5.56**
Hr 13	−0.86 (0.04)	−1.92 (0.09)	**−2.78**	−0.95 (0.04)	−5.99 (0.09)	**−6.93**	−2.13 (0.02)	−3.49 (0.06)	**−5.61**
Hr 14	−0.86 (0.04)	−1.92 (0.09)	**−2.78**	−0.95 (0.04)	−5.95 (0.09)	**−6.90**	−2.12 (0.02)	−3.47 (0.06)	**−5.59**
Hr 15	−0.74 (0.04)	−1.89 (0.09)	**−2.63**	−0.93 (0.04)	−5.74 (0.09)	**−6.66**	−2.11 (0.02)	−3.34 (0.06)	**−5.45**
Hr 16	−0.58 (0.04)	−1.80 (0.09)	**−2.38**	−0.94 (0.04)	−5.01 (0.09)	**−5.95**	−2.06 (0.02)	−2.73 (0.06)	**−4.79**
Hr 17	−0.42 (0.04)	−1.46 (0.09)	**−1.89**	−0.98 (0.04)	−3.04 (0.09)	**−4.02**	−1.87 (0.02)	−1.07 (0.06)	**−2.94**
Hr 18	−0.24 (0.04)	−1.17 (0.09)	**−1.41**	−0.57 (0.04)	−1.88 (0.09)	**−2.45**	−1.28 (0.02)	−0.37 (0.06)	**−1.65**
Hr 19	−0.17 (0.04)	−1.07 (0.09)	**−1.25**	−0.12 (0.04)	−1.42 (0.09)	**−1.54**	−0.55 (0.02)	−0.07 (0.06)	**−0.62**
Hr 20	−0.19 (0.04)	−0.95 (0.09)	**−1.14**	−0.16 (0.04)	−0.94 (0.09)	**−1.10**	−0.46 (0.02)	0.23 (0.06)	**−0.22**
Hr 21	−0.17 (0.04)	−0.83 (0.09)	**−1.00**	−0.16 (0.04)	−0.81 (0.09)	**−0.98**	−0.49 (0.02)	0.31 (0.06)	**−0.18**
Hr 22	−0.11 (0.04)	−0.81 (0.09)	**−0.92**	−0.11 (0.04)	−0.80 (0.09)	**−0.91**	−0.45 (0.02)	0.30 (0.06)	**−0.16**
Hr 23	−0.09 (0.04)	−0.73 (0.09)	**−0.83**	−0.09 (0.04)	−0.75 (0.09)	**−0.84**	−0.39 (0.02)	0.26 (0.06)	**−0.13**

Note: This table compares the impact of Interconnection ("Inter.") and Reinforcement ("Rein.") with and without investment effects, based on three sets of event study regressions. Columns 1–3 show the impact of market integration taking solar investments as given, where the dependent variable is the average hourly generation cost based on model simulation without investment effects. Columns 4–6 and columns 7–9 show two estimates for the impact of market integration with investment effects. In columns 4–6, the dependent variable is the average hourly generation cost based on model simulations with investment effects. We shift the timing of solar investment so that it occurs right after the interconnection and reinforcement (i.e., correct for anticipatory investment effects), use our structural model to obtain market outcomes, and rerun the event-study analysis. In columns 7–9, the dependent variable is the difference in model-simulated cost between the *actual scenario* case and the no market integration counterfactual with investment effects. We regress this time series on the two event dummies, including the same set of controls as in columns 1–6, except for the out-of-merit cost. Column 9 is the sum of columns 7 and 8.

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