Online Appendix for
"Market Impacts of a Nuclear Power Plant Closure"

Lucas Davis and Catherine Hausman

A1.1 Data Appendix

The annual plant-level electricity generation from the EIA are found in the *Power Plant Operation Report* (EIA-923). This is a required survey for all U.S. electric generating facilities with more than one megawatt of capacity. These data also contain information on plant characteristics, including operator name, fuel type, and some details about the generation technology. We supplement these characteristics with additional information (county, capacity, and vintage) from another Department of Energy dataset, the *Annual Electric Generator Report* (EIA-860).

The California Independent System Operator (CAISO) provides hourly electricity generation data, separated into broad categories (thermal, imports, renewables, large hydroelectric, and nuclear). About 90 percent of the electricity used in California is traded through CAISO. All of California's investor-owned utilities and most municipally-owned electric utilities buy power through CAISO. An important exception is the municipally-owned Los Angeles Department of Water and Power (LADWP), which maintains its own electricity generation and also imports power from other states through long-term contracts.

The EPA's CEMS data also contain hourly generation data, but at the generating unit level. Coverage is limited to thermal plants. Coverage has varied over time, but CEMS reporting requirements for California plants do not change during our sample period. In addition to these hourly data, the CEMS data provide descriptive information for each generating unit, including owner name, operator name, technology, primary and secondary fuel, and vintage. Additionally, we match each generating unit to one of the three price locations (South, Central, and North) using the "Control Area Generating Capability List" from CAISO (2013b).

In calculating the difference between net and gross generation, we examine generation data for 2005-2011 plants that appear in both CEMS and EIA. We calculate the annual net to gross ratio for each plant, using net generation as reported to EIA and gross generation as reported to CEMS. The median ratio is 0.966, but there are implausible outliers, such that the average is greater than 1. In particular, if some but not all generating units report to CEMS, this ratio can appear larger than 1. Dropping these outliers, the median is 0.957 and the average is 0.926. Kotchen and Mansur (2014) make a similar comparison using national data, finding a 5-percent mean difference. While we assume a 4.3 percent difference for our main specifications, results are similar using 2.15 percent or 8.6 percent.

To calculate marginal cost at the generating unit level for natural gas plants, we combine information on heat rates, natural gas prices, and variable operations and maintenance costs. As discussed in the "Background" section of the paper, separating fixed and variable operations and maintenance costs is challenging. Given the small magnitude of O&M at fossil-fuel plants, this distinction is not qualitatively important for our cost estimates. Below we discuss how we treat fixed O&M costs at SONGS and at California's natural-gas fired power plants. For the unit-level heat rate, we divide the total heat input over our time frame (in MMBtus) by total net generation (in MWhs). We obtain daily natural gas prices from Platts Gas Daily and calculate the average post-period price. We focus, in particular, on the PG&E City Gate price for the North, and the SCG City Gate price for the South. For variable O&M, we assume \$3.02 per MWh for combined cycle plants and \$4.17 per MWh for all other plants (in 2009\$), following CEC (2010).

To construct the marginal cost curve for all California, we again combine information on fuel costs and variable O&M costs. We use our estimates of marginal cost for all thermal units. For the capacity of these units, we use the maximum observed hourly generation in our sample. For hydroelectric, renewables, and nuclear, we proxy for capacity using the average hourly generation in the post-period (February 2012 through January 2013), from CAISO. While these types of generation have higher rated capacities, the average generation in the post-period is more relevant given constraints set by weather conditions. We assume zero marginal cost for hydro and renewables production. For the marginal cost of nuclear units, we use a nuclear fuel cost estimate of \$7.08 per MWh (in 2012\$) from Table 8.4 of the EIA's *Electric Power Annual* (EIA 2012), plus a nuclear variable O&M estimate for California of \$5.27 per MWh (in 2009\$) from CEC (2010). Biomass/biogas are not shown in the marginal cost figure, as marginal cost numbers are not available. The marginal cost of biomass generation is likely in the range of the combined cycle units with an average production over this period of around 500 MWh.

To calculate the annual fixed O&M costs at SONGS in Section 5.4, we used the Cost of Generation Model from CEC (2010). It reports an annual fixed O&M cost for California nuclear plants of 147.7 \$/kW-yr, in 2009 dollars. We multiplied this by the SONGS capacity of 2,150 MW and we translated into current dollars. This number closely matches regulatory documents, in which SCE had forecast fixed O&M costs of $346 million per year prior to the closure (CPUC 2012).

A1.2 Discussion of Potential Confounders

In this Online Appendix we evaluate the potential for confounding factors to influence our results. We are interested, in particular, in potential bias of our main estimates of predicted and residual changes. The following sections consider natural gas prices, other sources of in-state generation, entry and exit of generating units, imports, and demand. Although it is important to go through these potential confounding factors carefully, we end up concluding that overall our estimates are unlikely to be affected by changes in these other market conditions.

Before discussing the specific concerns, it is useful to clarify exactly what we mean by bias. Consider, for example, our estimates of predicted effects. Conceptually, what we hope to capture with our predicted estimates is the change in generation from the SONGS closure that would have occurred if there were no transmission constraints or other physical limitations of the grid. Implicitly, we want to hold everything else constant in this calculation so that the estimates reflect the true causal impact of the closure. Our empirical strategy is to build this counterfactual by constructing the unit-level generation curves using data from before the closure, and then to move up these curves by the amount of lost generation. An illustration is provided in Figure A1.

Thus, in some sense, no change to the market in 2012 could "bias" these results. Our predicted estimates are constructed using pre-closure data only, so they provide predicted changes in generation given the market conditions prior to 2012. An alternative approach for estimation would have been to use post-closure data to construct generation curves, and then to move down these curves by the amount of generation SONGS would have produced had it stayed open. Both approaches build a counterfactual for the SONGS closure, but we prefer our approach because it facilitates a straightforward decomposition of the impact into predicted and residual effects (see Figure A1). Since there is no information from 2012 in these estimates, it does not make sense to think about them being biased by anything that happened in 2012. Nonetheless, using pre-closure data to construct our counterfactual raises important questions about changes in market conditions. Put simply, are the market conditions in 2012 so different that our predictions based on pre-closure data are likely to be misleading? The primary objective of the following sections is to work through the different potential confounders. Even though market conditions are constantly changing, we end up concluding that overall our predicted estimates are unlikely to be meaningfully biased during the twelve months following the closure. As more time passes, conditions become considerably different from the pre-closure period; for this reason we focus on predicted estimates for the twelve months following the closure.

Conceptually, we want our residual estimates to reflect the difference between actual generation and the generation that would have occurred if there were no transmission constraints or other physical limitations of the grid. These estimates rely on the same counterfactual constructed for the predicted estimates, so all the same questions arise about potential confounders. There is also an additional potential concern for our residual estimates. The pattern of price differentials make it clear that transmission constraints and other physical limitations of the grid were more likely to bind post-closure. In the paper we attribute this change to the SONGS closure. The pattern of observed prices, both over time, and across California regions tends to support this interpretation. Nonetheless, it is important to consider the possibility there was some other simultaneous change in market conditions that influenced these constraints. We investigate several alternative explanations in the following sections and conclude that none of these alternatives can explain the particular pattern of geographic and temporal residuals that we see in the data.

A1.3 Changes in Natural Gas Prices

Figure A2 shows that there were large changes in natural gas prices during our sample period. Overall, natural gas prices were around 30 percent lower in 2012 than they were in 2011. These lower prices reduced the cost of replacing the lost generation from SONGS, relative to what one would have calculated based on 2011 prices. We emphasize this point in describing our results and use 2012 prices when quantifying the cost of increased thermal generation.

In addition, it is natural to ask whether these price changes could somehow bias our estimates of predicted and residual changes. In this section we evaluate several potential concerns and, at the same time, discuss closely related potential concerns about changes in the price of permits for Southern California's cap-and-trade program for nitrogen oxides (NOx). Permit prices affect the marginal cost of thermal generation and thus raise very similar questions to changes in natural gas prices, so it makes sense to address both at the same time. Overall, the evidence suggests that our results are unlikely to be meaningfully affected by these price changes.

The main potential concern is changes in the ordering of plants. Our unit-level regressions reflect the ordering of plants along the marginal cost curve. Plants with low heat rates are more efficient, producing large amounts of electricity per unit of fuel input, so these plants operate all the time. Plants with higher heat rates are less efficient, so they appear at the high end of the marginal cost curve and operate less frequently. If the changes in natural gas prices affected this ordering, this could bias our estimates of predicted and residual effects. We could make mistakes, for example, in predicting which plants would meet the lost generation from

SONGS.

Although this is a reasonable concern, there are several reasons why we would not expect much change in the ordering of plants. First, there is very little coal or other fossil fuels in the California electricity market, and thus little scope for inter-fuel changes in the ordering of plants. Nationwide the decrease in natural gas prices has led to widespread substitution of natural gas for coal (Cullen and Mansur, 2014), but essentially all of this has occurred outside the state of California. Second, a large fraction of California generation operates at close to zero marginal cost. This includes nuclear, 'run-of-the-river' hydro, geothermal, wind, and solar. These resources are ahead of natural gas in the queue, regardless of whether natural gas costs $2 or $7 per MMBtu. Third, the ordering of natural gas plants is largely unaffected by natural gas prices. The part of the marginal cost curve made up of by natural gas plants should be thought of, essentially, as an ordering of plants by heat rate. A decrease in natural gas prices reduces the marginal cost of generation for all plants, but the *ordering* is largely unaffected.[1]

Marginal cost also depends on NOx emissions where generators are subject to regional cap-and-trade programs for NOx. Under the RECLAIM program, certain generators in and around Los Angeles must remit permits corresponding to their NOx emissions. As it turns out, however, NOx permit prices were low enough during our sample period that they are unlikely to affect the ordering of plants.[2] In our data, the mean emissions rates for the Los Angeles area plants is 0.5 pounds per MWh (median 0.2 pounds per MWh). The average prices for NOx permits was $2493/ton in 2010, $1612/ton in 2011, and $1180/ton in 2012 (all in 2013 dollars), implying that NOx credit payments make up only a small portion of the plants' marginal costs.[3] Thus NOx permit obligations are unlikely to have meaningfully altered the ranking of plants by heat rate.

A more subtle concern would be differential changes in natural gas prices between the North and South. However, as can be seen in Figure A2, natural gas prices are quite similar in the North and South during the entire period. This makes sense given the network of existing pipelines as well as available storage, which can smooth out short-run capacity constraints in transmission. Although not visible in the figure, prices in the North decreased from the pre-

[1]Our methodology could still be applied in a setting with multiple fuel types (such as coal and natural gas) or with pipeline congestion leading to regional differences in natural gas prices. Predicted changes could be identified *within* each fuel type or each region, since that ordering would not be confounded by relative movements in fuel prices. The method would, however, be unable to distinguish cross-region or cross-fuel changes in the supply curve arising from transmission congestion as opposed to relative fuel price changes.

[2]We obtain annual average NOx prices from the Regional Clean Air Incentives Market ("RECLAIM") annual reports for 2006-present. Higher frequency prices are not publicly available. We use the prices of credits traded in the same year as the compliance year.

[3]The mean marginal cost would therefore be less than $0.60 in all three years, compared to wholesale electricity prices that are typically above $30. A small number of units have substantially higher NOx rates; the highest rate we observe in the Los Angeles area is 5 pounds per MWh.

to post-period approximately 2 percent more than in the South. This is a relatively small change, so we would not expect it to have much impact on the ordering of plants.

A1.4 Changes in Other Sources of Generation

Between 2011 and 2012 there were also significant changes in other sources of in-state electricity generation. Most importantly, 2012 was an unusually bad year for hydroelectric generation. The snowpack in 2012 was only half of the historical average level, and total hydroelectric generation in 2012 was less than 2/3rds generation in the previous year.[4] At the same time, almost 700 megawatts of wind and solar capacity were added in 2012 (CAISO 2013a), resulting in large percentage increases in generation from wind and solar. Geothermal and other renewables experienced essentially no change between 2011 and 2012. Finally, non-CEMS thermal units increased generation by five percent between 2011 and 2012.

This section discusses how these changes in other sources of generation could potentially impact our estimates or affect how the results are interpreted. As with the changes in natural gas prices, it is worth emphasizing that these changes are exogenous and should not be viewed as being *caused* by the SONGS closure. Year-to-year variation in hydroelectric generation is driven by idiosyncratic variation in precipitation. And, while new renewables capacity investments do respond to market conditions, it takes at least several years for planning and permitting a new site. The new wind and solar facilities that came online in 2012 were first envisioned in the early 2000s, long before there was any indication of potential safety concerns with SONGS.

It is also important to remember that we measure predicted effects using *net* system demand. When calculating demand for our unit-level regressions, we start with system-wide demand but then subtract from it all electricity generated by these other sources of generation. The generation that is left is what was met by CEMS units. Figure A3 shows a histogram of hourly total CEMS generation for each of these two periods, using the same bin width definition as in the regressions. Panel A shows one year of the pre-period and Panel B shows one year of the post-period. Total generation from CEMS units increases substantially in the post-period to fill in for SONGS and to make up for the decrease in hydro generation.

Changes to these other sources of generation are exogenous, so it does not make sense to think of these resources as making up for the lost generation from SONGS. Wind, solar, and non-dispatchable hydro have a marginal cost of operation near zero, so they operate regardless of what else is happening in the market. California's one other nuclear power plant, Diablo

[4] For historic snowpack levels see the Snow Water Equivalents data from the Department of Water Resources at http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action. On April 1, 2012, the snowpack was at 54 percent of the historical April 1 average.

Canyon, also has very low marginal cost and operates around the clock. Moreover, the non-CEMS thermal units tend to be industrial, commercial, and cogeneration facilities for which electricity generation is a joint decision with other processes, limiting their ability and incentive to respond to market conditions.

Dispatchable hydroelectric generation is somewhat harder to think about, but it is also unlikely to be making up for the lost generation from SONGS. Year-to-variation in precipitation determines total hydroelectric generation, but operators have some flexibility as to *when* these resources are utilized. Short-run generation decisions are determined by a complex dynamic optimization problem. Operators respond to current and expected market conditions, trading off between current prices and the shadow value of the remaining water in the reservoir, subject to minimum and maximum flow constraints. None of this is particularly problematic for our analysis because operators are optimizing the same problem both before and after the SONGS closure. Moreover, the generation curve for large hydro in Figure 3 indicates only a modest amount of intertemporal substitution toward high demand periods.

A related question is how changes in these other sources of generation could have changed the likelihood that the transmission constraints were binding, thus indirectly impacting the ordering of thermal resources. This is potentially problematic because we would like to attribute the observed residual effects to the SONGS outage. Of the other changes in generation, by far the most significant is the decrease in hydro generation. Although this is an important consideration, the decrease in hydroelectric generation in 2012 would have, if anything, made transmission constraints *less* likely to bind. Hydroelectric plants are located primarily in the North,[5] and according to EIA data, 75 to 80 percent of the fall in hydro generation in 2012 occurred in the North. As such, the decrease in hydroelectric generation would have, if anything, actually reduced the need for North to South transmission. Moreover, the changes in wind and solar generation, while large percentage increases, represent small changes when compared to the entire market, and thus are unlikely to have meaningfully contributed to the binding transmission constraints and other physical limitations of the grid. Wind and solar generation statewide increased by 0.17 million and 0.04 million MWh per month, respectively, in 2012.[6] Total monthly generation in California in 2012 was almost 17 million MWh, so these increases combined represent only about 1 percent of total generation.

[5] According to CAISO (2013b), approximately 80 percent of summer capacity is in the North.

[6] According to EIA data, most of this increase in wind and solar generation was in the North. However, the magnitude is much smaller than the decrease in hydro generation. Consequently, the net change in the North for other sources of generation (i.e., hydro plus renewables) was still negative and two to three times the decrease in generation in the South. These exogenous changes would have, if anything, reduced the need for North to South generation.

A1.5 Entry and Exit of Thermal Units

During our sample period, a number of thermal generating units opened or closed, and in this section we discuss the impact of this entry and exit on the interpretation of our estimates. The results in the paper focus on a balanced panel of units, restricting the sample to those units that were continually in service during our sample period of April 20, 2010 through January 31, 2013. As we mention in the paper, we also include Huntington Beach units 3 and 4, which operated for most of this period, but were converted to synchronous condensers in January 2013. Excluding units that enter and exit simplifies the analysis and interpretation but also raises two potential concerns. First, our results could be biased if the entry and exit were endogenous to the closure of SONGS. In particular, it would be a causal effect of SONGS that we are failing to capture. Second, for entry and exit that is either endogenous or exogenous, a separate concern is that these changes could somehow have affected transmission congestion and thus biased our residual effects.

Entry and exit in 2010 and 2011 is clearly exogenous, since the closure of SONGS was unanticipated. We exclude five units that exited in 2010; these units had accounted for 1 to 2 percent of California CEMS generation before their closure. We additionally exclude units that enter in 2010 or 2011, before the SONGS closure was anticipated; these units accounted for 3.5 percent of California CEMS generation in 2012 and 1.8 percent of total California generation. We simply do not have enough pre-period data from these plants to include them in the analysis. Fortunately, this is a small enough part of the market that excluding these plants is unlikely to meaningfully bias our estimates.

Endogenous entry and exit in 2012 are almost certainly not a concern given the short time horizon. New units take years to plan and permit, and the closure of SONGS was unexpected. To verify this, we examined siting documents from the California Energy Commission for the units that opened in 2012. Altogether, these units accounted for less than 1 percent of total California generation. Where we were able to locate the siting documents, we found that applications had been filed in 2008 or 2009, long before the SONGS closure. It is possible that these openings may have been accelerated by the SONGS closure, but we are unaware of any specific cases. In short, we do not think it makes sense to think of this entry as a causal response to the SONGS closure.[7]

More plausibly, the SONGS outage could have delayed plant exit. To the best of our knowledge, the only such case is the extension of operations at Huntington Beach's units 3 and 4. These two units were expected to retire about the same time that SONGS closed,

[7] A related possibility is that existing units made capital investments to change their heat rate or capacity. If caused by the SONGS closure, this would be one of the mechanisms through which our effects operate. If not caused by SONGS, it would confound our results only if it affected transmission congestion.

but remained open in 2012 to provide additional generation and voltage support in Southern California (CAISO 2013a). These units are in our sample, so this generation is reflected in our results. In addition, for these units we estimate an extra year's worth of fixed operations and maintenance costs to be around $4 million.[8] This cost is small in comparison to the generation cost increase caused by the SONGS closure. It is also very small in comparison to the fixed operations and maintenance costs at SONGS itself; this is in part because the two Huntington Beach units are smaller, and in part because fixed O&M costs are much lower at natural gas units than at nuclear units.

Whether endogenous or exogenous, a separate concern is that this entry and exit could have affected transmission constraints. In the paper we attribute the increase in transmission constraints observed in 2012 to the SONGS closure. However, suppose, for example, that a large plant had opened in Northern California at exactly the same time that SONGS closed. In this case there would actually be two complementary explanations for the increase in transmission constraints, and it would be misleading to focus entirely on SONGS. As it turns out, net entry during the twelve months following the SONGS closure was larger in the North than the South, by approximately 130 MWh on average per hour. Thus, net entry was in the direction that would have tended to exacerbate transmission constraints. That said, the magnitude of the net entry is small compared to the 2,150 MWh per hour typical generation from SONGS. Moreover, the net entry is also small compared to the year-to-year change in hydro generation. As we report in Table 2, hydro generation in California decreased by 1,700+ MWh per hour (1.25 million MWhs on average per month) between 2011 and 2012. As we reported in Section A1.3, 75 to 80 percent of this decrease occurred in the North. This year-to-year decrease in hydro generation dwarfs the change in net entry, implying that the overall impact of these combined changes to generation (from net entry, hydro, other renewables, etc.) would have been, if anything, to reduce transmission congestion between Northern and Southern California. In short, we conclude that entry and exit cannot provide an alternative explanation for the transmission constraints observed post-closure.

A1.6 Imports

Imports make up 30 percent of total electricity supply in California. In calculating our predicted effects we have implicitly assumed that none of the lost generation from SONGS is met by out-of-state generation. Whether or not this is a reasonable assumption depends on the impact of the SONGS closure on prices and on the elasticity of supply for imports. Our

[8] The Cost of Generation Model from CEC (2010) reports an annual fixed O&M cost for California combustion turbine plants of 8.3 $/kW-yr, in 2009 dollars (it does not report a number for steam boilers). We multiplied this by a capacity of 440 MW and translated into current dollars.

results suggest that price impacts were likely modest. During most hours equilibrium in the California electricity market occurs along the long inelastic part of the marginal cost curve, so one would not have expected the SONGS closure to have a substantial impact on prices. In addition, during the hours in which equilibrium occurs along the steep part of the marginal cost curve, imports were largely unresponsive.

Empirically, the elasticity of supply for imports appears to be relatively low. As shown in Figure 3, imports increase with system demand, but not very much, and most of the increase occurs at relatively low demand quantiles. Above the median system-wide demand, there is essentially no observable increase in imports. Averaging across all hours, imports increase by an average of 519 megawatt hours when total demand increases by 2,150 MWh. This is equivalent to 25 percent of the lost generation from SONGS. This suggests that we could reduce our predicted estimates in Panel A of Table 3 by 25 percent. For the cost estimates, however, we do not expect much of an adjustment needs to be made. Since the in-state generation marginal cost curve is quite elastic in most hours, the cost of out-of-state generation must have been close to the marginal cost of the in-state generation. As a result, the cost estimates we report in the paper should be close to the true change in total cost accounting for imports.

Interestingly, the change in imports during weekday summer afternoons and high demand hours was much lower. During weekday summer afternoons, imports in 2012 increased on average by only 90 megawatt hours, and during high demand hours the increase was less than 10 megawatt hours. This is consistent with interstate transmission constraints or other physical limitations of the grid preventing larger increases in imports during these hours. Alternatively, it could simply reflect that demand is correlated across states, i.e. it tends to be hot in Nevada and California at the same time, and so the elasticity of supply for imports becomes very inelastic in these periods.

From the perspective of interpreting our results it doesn't particularly matter *why* imports are not responding more. This lack of responsiveness in high demand hours means that the estimates in Panels B and C of Table 4 are approximately correct. Incorporating imports would reduce our estimates in these panels by only 4 percent and 1 percent, respectively, reflecting the relatively small portion of the lost generation from SONGS that appears to have been met with imports.

A1.7 Electricity Demand

Statewide demand for electricity was slightly higher in 2012 than 2011 due to warm weather. We calculate our predicted effects using the distribution of system-wide demand in 2012, so our estimates reflect this higher overall level of demand. Hence, there is no sense in which this aggregate change in electricity demand is biasing our estimates. Still, in the paper, we would like to attribute the increase in transmission constraints to the SONGS closure, so it would be worth knowing if the changes in electricity demand are large enough to provide an alternative explanation.

Had SONGS closed during a cooler year, it would have been less expensive to meet the lost generation, and transmission constraints would have been less binding. While this is undoubtedly true, the same could be said about hydroelectric generation, natural gas prices, and other factors. Throughout the analysis we have tried where possible to have our estimates reflect actual market conditions in 2012.

A related question is how to think about demand response. Implicitly, our analysis assumes that electricity demand is perfectly inelastic. We calculate our predicted effects by moving along the generation curves by 2,150 MWhs, the entire lost generation from SONGS. This assumes that demand is perfectly inelastic. Although this assumption is common in the literature, it is obviously not exactly right. Although the vast majority of customers do not face real-time prices, retail electricity prices do respond month-to-month to change in generation costs. Moreover, there are some industrial customers who face prices that update more frequently. The size of the demand response depends on how much prices changed and the price elasticity of demand. The SONGS closure shifts the marginal cost curve to the left, increasing prices. Our results suggest, however, that in the vast majority of hours this price impact would have been fairly modest, because demand was crossing a fairly elastic portion of the marginal cost curve. Moreover, most estimates of the price elasticity of demand[9] suggest that even in the medium-term, demand is not very elastic.[10] Thus evaluating the change in supply required to make up the entire 2,150 MWhs of lost generation is likely a very good approximation.

A more subtle concern is whether differential changes in demand across region could have impacted transmission constraints. To evaluate this, we obtained hourly demand for three geographic regions within California, corresponding closely to the Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric service territories (the former in the North, and the latter two in the South). In Figure A4, we show the total weekly quantity demanded for all three regions across time. While not large, there does appear to be a divergence in the summer of 2012 between the PG&E and SCE quantities, reflecting

[9] Ito (2014), for example, finds a price elasticity of less than -0.10 with respect to retail prices for a sample of California households.

[10] There are also explicit "demand response" programs operated by the three California investor-owned utilities. The use of these programs increased between 2011 and 2012, but from a very low baseline level. Total estimated demand reductions from of all California demand response programs in 2012 was 25,882 megawatt hours (CAISO 2013a, p. 34). This is less than 0.01 percent of total electricity in the market, and equivalent to only 12 *hours* of generation from SONGS. Moreover, there are serious challenges with these programs that limit CAISO's ability to effectively target modest resources to hours and locations when and where they would be most valuable (CAISO 2013a, pp. 35–37).

a warmer than average summer in the South. However, in Figure A5, we show preliminary evidence that this is unlikely to explain much of the price difference we see in the post-period. This graph plots the price difference between the SP26 and NP15 pricing regions, as well as the demand difference between the South (SCE plus SDG&E) and the North (PG&E). While the demand difference between the North and South increased in late 2012, the price difference increased much sooner and persisted much longer.

To more formally address the concern that our residual results could have been driven by the changes in demand, we examined results from an alternative specification in which we estimate equation (1) conditioning on the demand *difference* between North and South. Specifically, we calculate the difference between South (SCE plus SDG&E) and North (PG&E), then construct a series of equal-width bins. These bins are interacted with the demand bins in the unit-level generation regressions. The predicted results (available upon request) are qualitatively similar to those in Table 3. The point estimates of the residual results are generally around 10 percent smaller than in Table 3, although they are not statistically different. This may indicate that a small portion of the congestion was attributable to the difference in demand.

A1.8 Placebo Tests for Residual Effects

To provide further evidence that the observed residual effects are unusual, and not driven by idiosyncratic unobservables, we next provide a series of placebo tests. We repeat our analysis six times, estimating the model as if SONGS had closed in different years (2006, 2007, ... and 2011). Figure A6 shows the residual changes for each placebo, with separate results (as in our main analysis) for all hours, weekday summer afternoons, and high demand hours.

The figure shows that some of the estimated residual effects from other years are similar in size to the estimates for 2012. In 2007, for instance, the South saw positive residual changes, whereas the North saw negative changes. However, the results for 2012 differ more dramatically from the placebo results when one accounts for the unusual behavior at AES-owned facilities. In Figure A7, we again show six placebo tests, but based on estimates from a sample that excludes AES. In these results, the 2012 large positive changes in the South and large negative changes in the North are more apparent than in the previous figure.

Moreover, closer inspection of the residual results in other years shows that they are largely driven by extended outages at single plants, rather than by correlated changes across plants. To demonstrate this, Figure A8 shows a series of additional statistics from these placebo tests. In particular, we calculate the standard deviation, skewness, and kurtosis of our estimated unit-level residuals. For years with the largest average residuals by zone (especially 2007 and 2009), the presence of outliers is clear in these diagnostics. These years have higher standard deviations, skewness (in absolute terms), and kurtosis than our main sample, indicating the presence of outliers.

We also calculate the residual change in generation costs implied by each placebo. As we report in Table 5, our estimate is $40 million per year. This estimate is higher than all six estimates based on placebos, but in some placebo samples the estimate is close in magnitude to $40 million. This reflects extended outages at different plants and other unmodeled year-to-year changes in the market. Overall, the placebo test results indicate that the pattern of generation and cost results we see in 2012 is indeed unusual, though not significantly outside of the range observed in other years. None of this calls into question the estimated first-order effects (i.e. the $311 million increase in generation costs), but it suggests that the residual effects should be interpreted cautiously.

References

California Energy Commission (CEC). 2010. "Cost of Generation Model Version 2." *Accessed from http://www.energy.ca.gov/2010publications/CEC-200-2010-002/.*

California Independent System Operator (CAISO). 2013*a*. "Annual Report on Market Issues and Performance, 2012." *Accessed from http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf.*

California Independent System Operator (CAISO). 2013*b*. "Master CAISO Control Area Generating Capability List." *Accessed from http://www.caiso.com/Documents/GeneratingCapabilityList.xls.*

California Public Utilities Commission (CPUC). 2012. "Decision on Test Year 2012 General Rate Case for Southern California Edison Company." *Accessed from http://www.edison.com/files/2012GeneralRateCaseProposedDecision101912.pdf.*

Cullen, Joseph, and Erin T. Mansur. 2014. "Inferring Carbon Abatement Costs in Electricity Markets: A Revealed Preference Approach using the Shale Revolution." *NBER Working Paper 20795.*

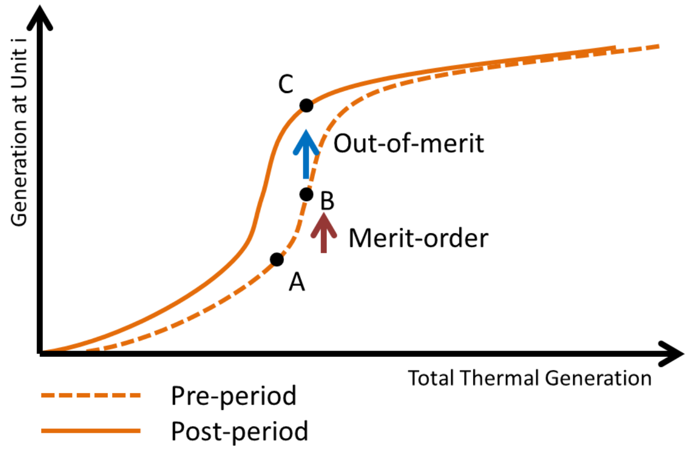
Energy Information Administration (EIA). 2012. "Electric Power Annual." *Accessed from http://www.eia.gov/electricity/annual/.*

Ito, Koichiro. 2014. "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing." *American Economic Review*, 104(2): 537–663.

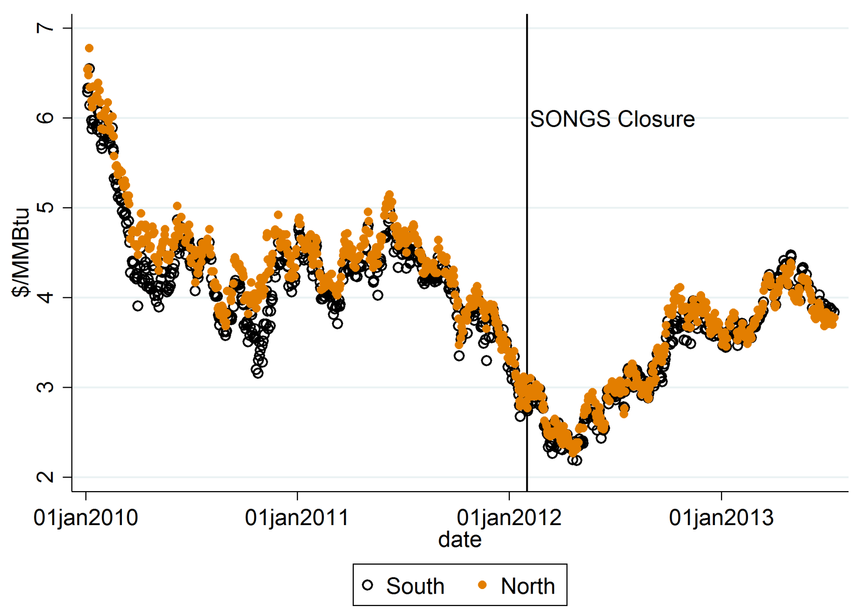
Kotchen, Matthew J., and Erin T. Mansur. 2014. "How Stringent Are the US EPA's Proposed Carbon Pollution Standards for New Power Plants?" *Review of Environmental Economics and Policy*, 8(2): 290–306.

Online Appendix

Appendix Figure A1: Predicted and Residual Effects

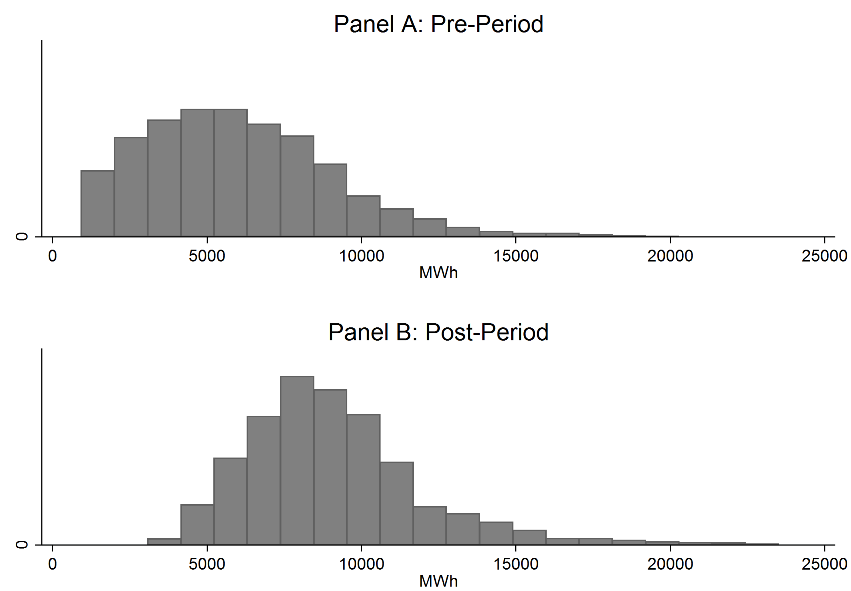


Appendix Figure A2: Natural Gas Prices, by Region



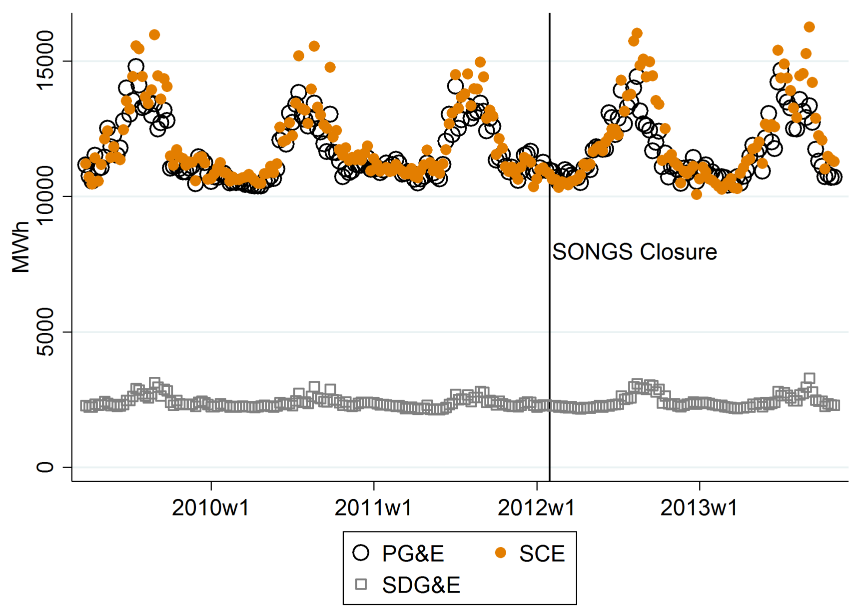
Note: This figure plots daily natural gas prices, in $/MMBtu, for Northern California (PG&E citygate) versus Southern California (SCG citygate). Data are from Platts Gas Daily.

Appendix Figure A3: Histogram of Hourly Total CEMS Generation



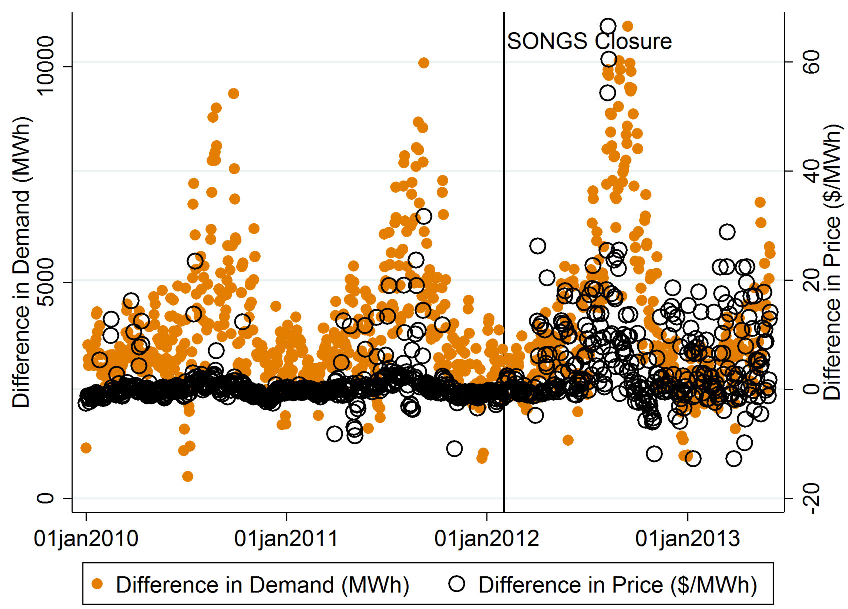
Note: This figure shows histograms of total hourly generation from CEMS units in the year leading up to the SONGS closure (Panel A) and in the year following the closure (Panel B). The shift to the right in Panel B reflects both the closure of SONGS and concurrent changes in non-thermal generation (especially hydro) and demand.

Appendix Figure A4: Regional Demand



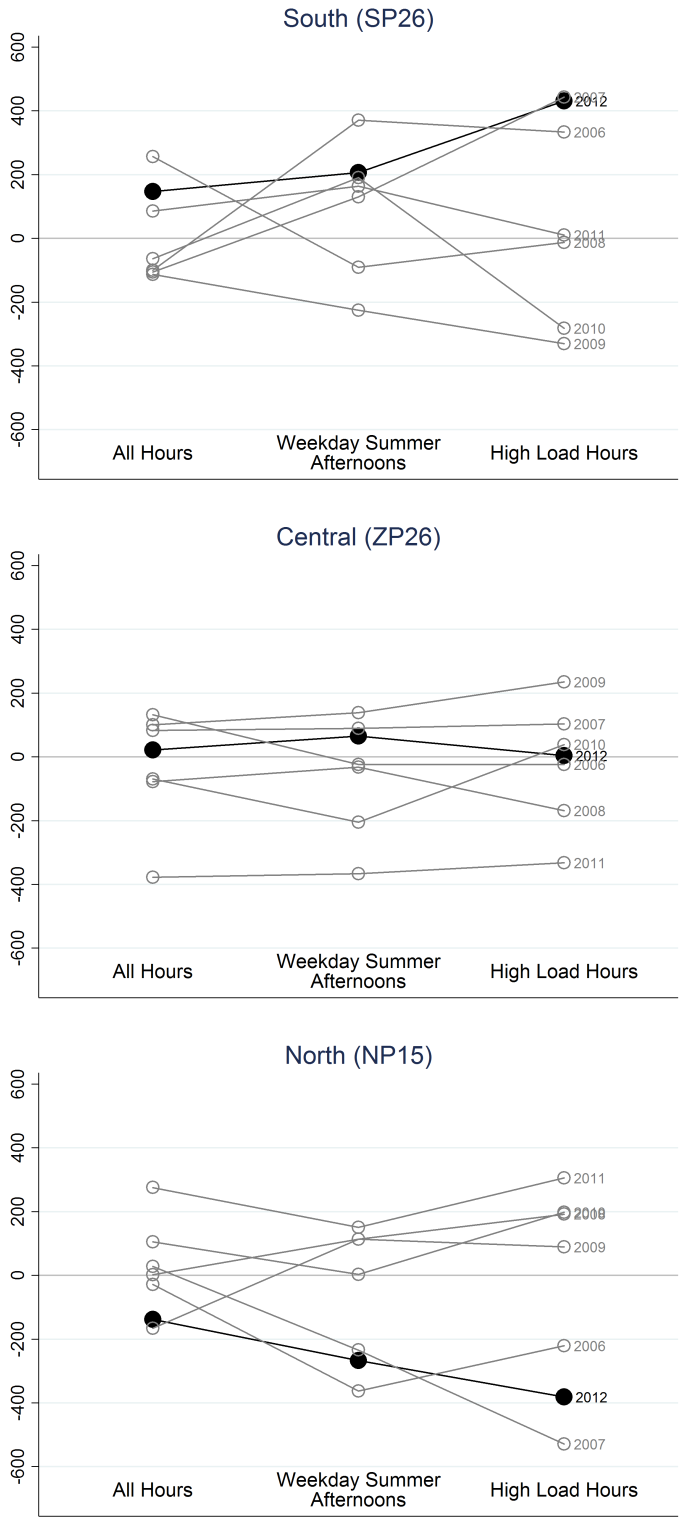
Note: This figure plots average hourly quantity demanded by week for the three California investor-owned utilities. The vertical line shows the week the second SONGS unit went down. PG&E is roughly the Northern half of the state, SCE is the Southern half excluding the San Diego area, and SDG&E is the San Diego area.

Appendix Figure A5: Regional Demand and Price Differentials



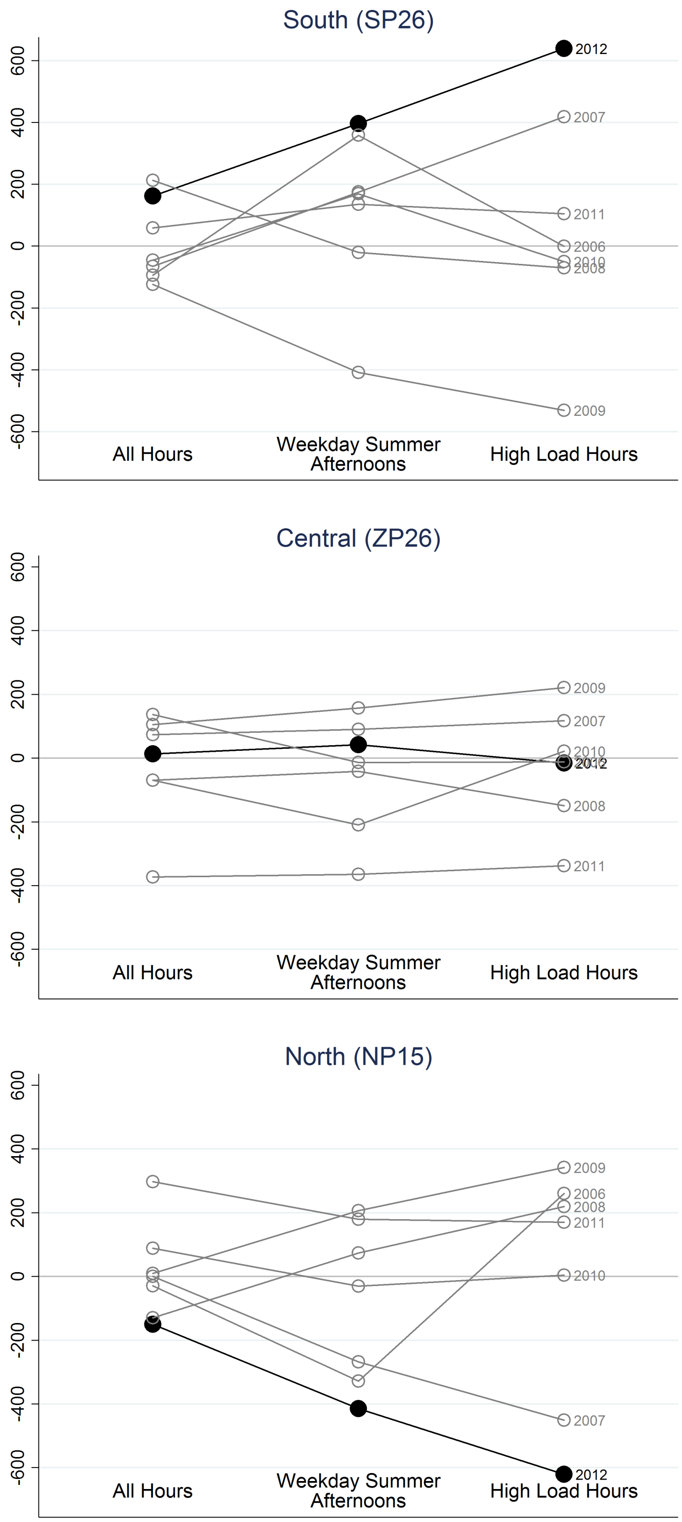
Note: This figure plots quantity demanded and price differentials at 3 pm daily between January 2009 and September 2013. Weekends are excluded. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Appendix Figure A6: Residual Changes, by Year



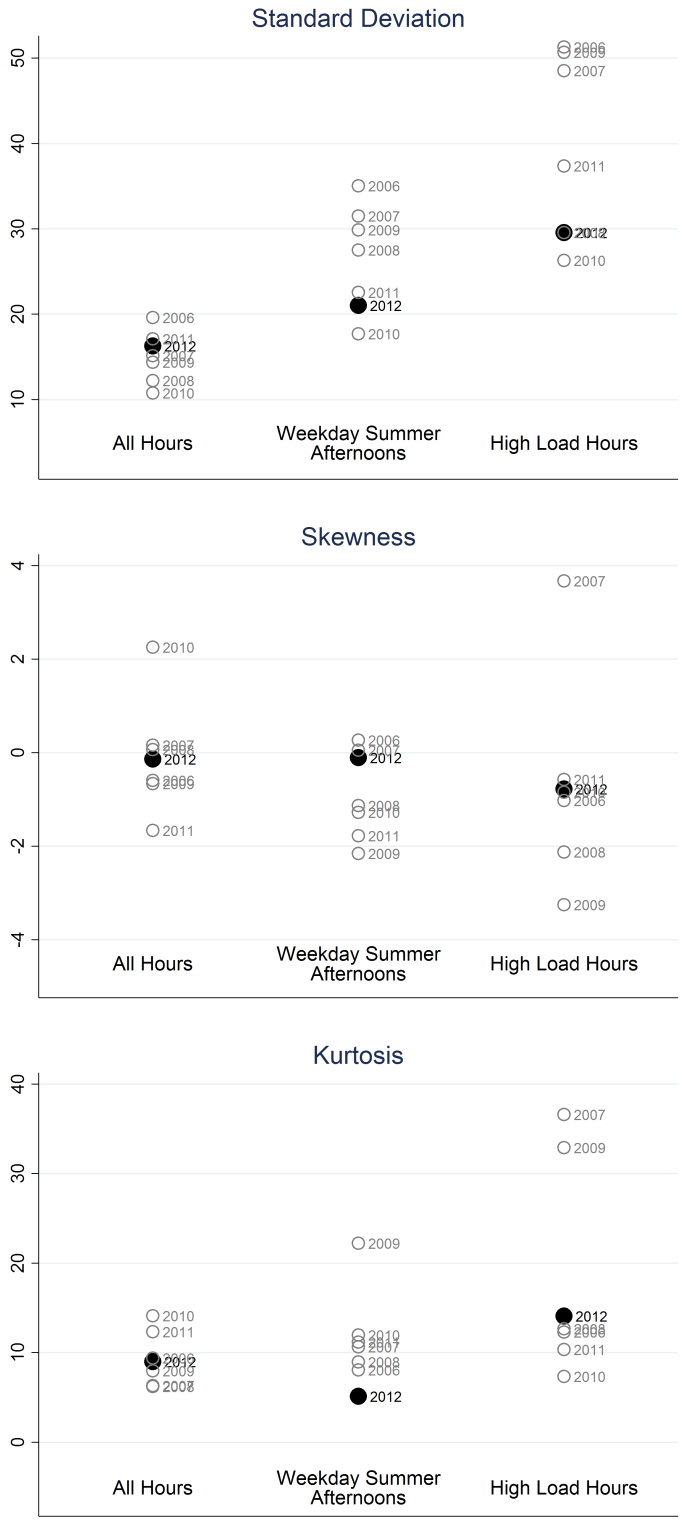
Note: These figures show residual estimates for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A7: Residual Changes, without AES, by Year



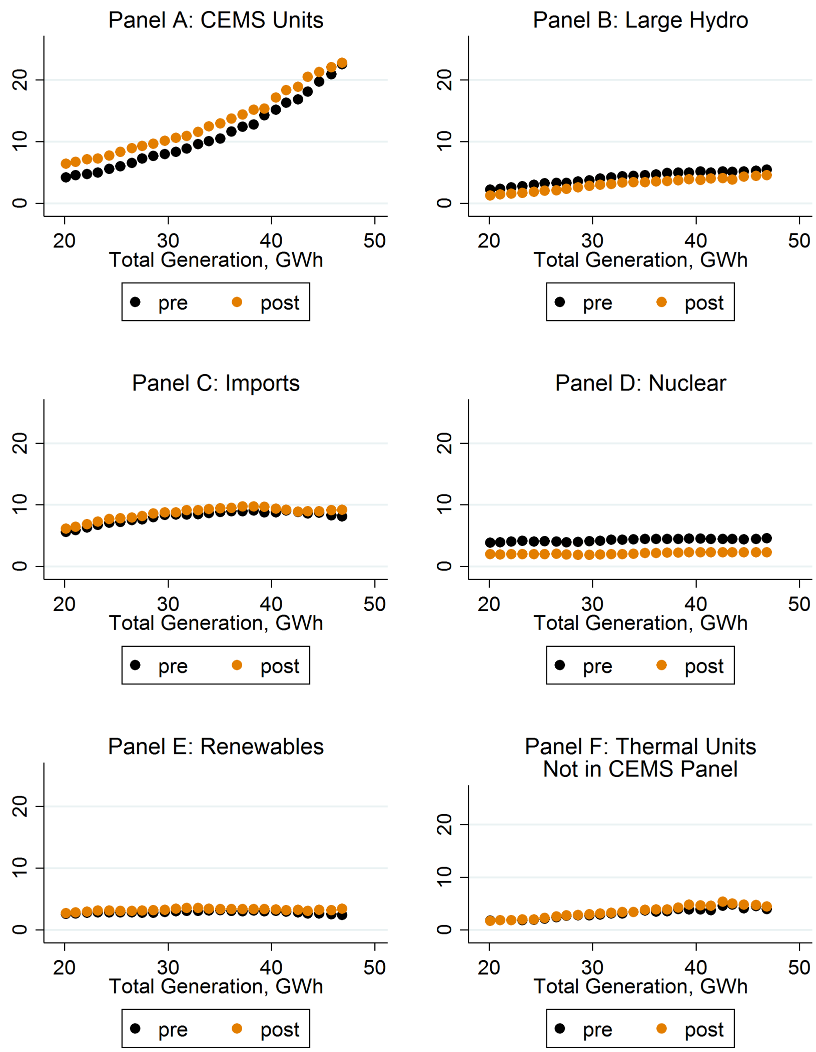
Note: These figures show residual effects based on estimates from a sample that excludes AES plants for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A8: Unit-Level Diagnostics, by Year



Note: These figures show unit-level diagnostics on the residual estimates, for the main sample of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

Appendix Figure A9: Generation Regressions by Category



Note: This figure was constructed in the same way as Figure 3 in the main text, but using data from both the pre-period and the post-period. The x-axis shows the quantile of total generation from all sources and the y-axis shows the average generation, in GWh, for that category of generation.

Online Appendix

Appendix Table A1: California Electricity Generation By Source, 2011

Category	Subcategory	Percentage
Fossil Fuels	Natural Gas	44.3
	Coal	1.0
	Other Fossil Fuels	1.7
	Total	**47.0**
Nuclear	San Onofre	9.0
	Diablo Canyon	9.2
	Total	**18.3**
Renewables	Hydroelectric	21.1
	Geothermal	6.3
	Wind	3.9
	Solar (PV and Thermal)	0.4
	Other Renewables	3.0
	Total	**34.7**
Total		**100.0**

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report*, which reports net generation from all electric generating plants larger than one megawatt. We include all facilities operating in California. "Other Fossil Fuels" includes petroleum coke, distillate petroleum, waste oil, residual petroleum, and other gases. "Other Renewables" includes wood, wood waste, municipal solid waste, and landfill gas.

Appendix Table A2: Largest Plants not in CEMS

Plant Name	Operator	Sector	Prime Mover	County	Fuels	Million MWh in 2011	Million MWh in 2012	Summer Capacity, MW	Capacity Factor, 2011	Vintage
Panel A: Non-Cogen Natural Gas Plants										
Humboldt Bay	PG&E	Utility	Internal Combust.	Humboldt	Natural Gas, Petroleum	0.5	0.4	167	0.32	1956*
Wheelabrator Shasta	Wheelabrator Environmental Systems	IPP	Steam Turbine	Shasta	Wood Waste	0.4	0.4	60	0.74	1987
Desert View Power	Desert View Power Inc	IPP	Steam Turbine	Riverside	Wood Waste, Nat. Gas, Tires	0.3	0.3	47	0.83	1991
SEGS IX	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.29	1990
SEGS VIII	FPL	IPP	Steam Turbine	San Bernardino	Solar, Natural Gas	0.2	0.2	88	0.28	1989
Panel B: Cogen and Industrial Natural Gas Plants										
Watson Cogeneration	ARCO Products Co-Watson	Industrial	Combined cycle	Los Angeles	Nat. Gas, Other Gases, Waste Oil	3.0	3.1	398	0.86	1987
Crockett Cogen Project	Crockett Cogeneration	IPP Cogen	Combined cycle	Contra Costa	Natural Gas	1.8	1.7	247	0.84	1995
Sycamore Cogeneration	Sycamore Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.5	1.4	300	0.57	1987
Midway Sunset Cogen	Midway-Sunset Cogeneration Co	Industrial	Gas turbine	Kern	Natural Gas	1.4	1.4	219	0.72	1989
Kern River Cogeneration	Kern River Cogeneration Co	IPP Cogen	Gas turbine	Kern	Natural Gas	1.3	1.3	288	0.50	1985
Panel C: Other Plants										
Diablo Canyon	PG&E	Utility	Steam Turbine	San Luis Obispo	Nuclear	18.6	17.7	2240	0.95	1985
San Onofre	SCE	Utility	Steam Turbine	San Diego	Nuclear	18.1	0.8	2150	0.96	1983
Geysers Unit 5-20	Geysers Power Co LLC	IPP	Steam Turbine	Sonoma	Geothermal	4.7	4.8	770	0.70	1971
Shasta	U S Bureau of Reclamation	Utility	Hydro	Shasta	Hydro	2.4	1.8	714	0.38	1944
Edward C Hyatt	CA Dept. of Water Resources	Utility	Hydro	Butte	Hydro	1.9	1.4	743	0.30	1968

Note: These data come from the U.S. Department of Energy *Power Plant Operations Report* and *Annual Electric Generator Report*. The table describes 2011 net generation for plants operating in California. "Largest" is defined according to net generation reported to EIA in 2011. Vintage refers to the year the plant started commercial operation. *Humboldt Bay was in CEMS until 2010 but dropped out after that, when the all of the plant's combustion turbine and steam boiler units were replaced with reciprocating engine generators.

Appendix Table A3: Most Affected Plants, All Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Predicted Change (MWhs)	Residual Change (MWhs)
Panel A. Predicted Increases, Top Five								
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	227	59
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	168	100
3	Pastoria	Calpine	Comb Cyc	SP15	25/26/26	764	142	-37
4	Delta	Calpine	Comb Cyc	NP15	26/27/27	896	126	25
5	Mountainview	SCE	Comb Cyc	SP15	25/26/26/26	1068	126	3
Panel B. Residual Increases, Top Five								
1	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	143
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	168	100
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	23	87
4	High Desert	Tenaska	Comb Cyc	SP15	39/39/40	492	91	82
5	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	227	59
Panel C. Residual Decreases, Top Five								
1	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	101	-114
2	Inland Empire	General Electric	Comb Cyc	SP15	24/25	752	61	-111
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	101	-94
4	Gateway	PG&E	Comb Cyc	NP15	27/27	590	84	-72
5	Cosumnes	SMUD	Comb Cyc	NP15	26/26	523	41	-41

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. †EME refers to Edison Mission Energy.

Appendix Table A4: Most Affected Plants, Weekday Summer Afternoons

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Predicted Change (MWhs)	Residual Change (MWhs)
			Panel A. Predicted Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	236	43
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
3	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
4	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
5	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	88	-67
			Panel B. Residual Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	30	158
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	26/26/26/26	1066	152	125
3	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	89	118
4	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	54	98
5	Elk Hills	Occidental Petroleum	Comb Cyc	ZP26	26/27	548	11	86
			Panel C. Residual Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	181	-213
2	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	54	-105
3	Calpine Sutter	Calpine	Comb Cyc	NP15	25/26	564	60	-94
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	28	-80
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	25	-76

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in the CEMS data. Weekday summer afternoons include the hours 2 p.m. to 5 p.m. in months June through September. †EME refers to Edison Mission Energy.

Appendix Table A5: Most Affected Plants, High Demand Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Predicted Change (MWhs)	Residual Change (MWhs)
			Panel A. Predicted Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	27/27/27/27/37/37	2541	251	-62
2	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	238	-196
3	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	130	-122
4	El Segundo	NRG	Boiler	SP15	41/42	658	130	113
5	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	124	154
			Panel B. Residual Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	36/38/38/38/41/42	636	33	257
2	Cabrillo I Encina	NRG	Boiler	SP15	41/41/42/44/44	954	124	154
3	Otay Mesa	Calpine	Comb Cyc	SP15	26/26	596	10	117
4	El Segundo	NRG	Boiler	SP15	41/42	658	130	113
5	Ormond Beach	NRG	Boiler	SP15	40/41	1490	98	108
			Panel C. Residual Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	41/41/42/43/46/47	1934	238	-196
2	AES Redondo	AES	Boiler	SP15	40/44/55/64	1348	130	-122
3	Panoche	Energy Investors Fund	Combust Turbine	NP15	35/35/35/35	412	53	-116
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/38	186	33	-97
5	Sunrise	EME† and ChevronTexaco	Comb Cyc	ZP26	25/25	577	21	-77

Note: The regressions for this table are identical to those in Table 3, but at the plant level. Owner and plant type data are from CEMS documentation, cross-checked against industry sources. The zones are as follows: NP15: Northern California, ZP26: Central California, and SP26: Southern California. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (greater than 13,837 MWh). †EME refers to Edison Mission Energy.

Appendix Table A6: Separating Alamitos and Redondo

	Average Hourly Change, By Region			
	AES	Southern California, Excluding AES	Central California	Northern California
	(1)	(2)	(3)	(4)
	Panel A: All Hours			
Predicted Change (MWh)	110	781	300	944
	(15)	(15)	(15)	(18)
Residual Change (MWh)	-32	182	20	-140
	(60)	(53)	(66)	(49)
	Panel B: Weekday Summer Afternoons			
Predicted Change (MWh)	339	729	259	822
	(31)	(27)	(17)	(39)
Residual Change (MWh)	-311	548	76	-260
	(94)	(105)	(61)	(119)
	Panel C: High Demand Hours			
Predicted Change (MWh)	455	752	174	753
	(42)	(34)	(30)	(35)
Residual Change (MWh)	-310	742	4	-381
	(127)	(111)	(57)	(129)
Observations (Hour by Unit)	340,340	1,944,800	267,410	1,920,490
Number of Generating Units	14	80	11	79
Number of Plants	3	39	5	43
Total Capacity (MW)	4,167	11,755	2,887	11,776

Note: The format of the table and underlying data are identical to Table 3, but we have separated plants owned by AES from other Southern plants. The three AES plants are Alamitos, Redondo Beach, and Huntington Beach. AES and JP-MorganChase had tolling agreements for all three plants.

Appendix Table A7: Including 2013

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Predicted Change in Net Generation (MWh)	883	301	950
	(19)	(17)	(18)
Residual Change in Net Generation (MWh)	63	40	-78
	(77)	(70)	(75)
	Panel B: Weekday Summer Afternoons		
Predicted Change in Net Generation (MWh)	1037	278	853
	(43)	(15)	(35)
Residual Change in Net Generation (MWh)	191	22	-193
	(126)	(77)	(107)
	Panel C: High Demand Hours		
Predicted Change in Net Generation (MWh)	1214	183	748
	(41)	(29)	(36)
Residual Change in Net Generation (MWh)	390	-15	-348
	(141)	(61)	(131)
Observations	2,565,420	306,735	2,202,915
Number of Generating Units	92	11	79
Number of Plants	42	5	43
Total Capacity Represented (MW)	15,498	2,935	11,782

Note: This table was constructed in the same way as Table 3, except that data were also included for February through June of 2013.