Market Impacts of a Nuclear Power Plant Closure

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Abstract

Falling revenues and rising costs have put U.S. nuclear plants in financial trouble, and some threaten to close. To understand the potential private and social consequences, we examine the abrupt closure of the San Onofre Nuclear Generating Station (SONGS) in 2012. Using a novel econometric approach, we show that the lost generation from SONGS was met largely by increased in-state natural gas generation. In the twelve months following the closure, natural gas generation costs increased by $350 million. The closure also created binding transmission constraints, causing short-run inefficiencies and potentially making it more profitable for certain plants to act non-competitively.

Key Words: Nuclear Power, Electricity Markets, Transmission Constraints, Carbon Emissions
JEL: L51, L94, Q41, Q54

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1 Introduction

Nuclear power has historically supplied a substantial portion of electricity – 20 percent in the United States and 14 percent worldwide for 2000 to 2012. As recently as 2008, the outlook for the industry was robust, with nuclear plants earning large profits. Since 2009, however, prospects for nuclear power – even at existing facilities – have substantially waned, with the closure of several large facilities and predictions of more closures to come (EIA 2014). Multiple factors have contributed to the recent closures of nuclear plants. Peak wholesale electricity prices fell around 50 percent in real terms from 2007 to 2012,[1] a result of both falling natural gas prices and stagnant electricity demand. At the same time, costs for nuclear plants have been rising, a combination of rising wages and fuel prices, stricter safety regulations, and the aging of decades-old equipment.

To many observers, low profitability at *existing* nuclear plants is surprising, since the marginal cost of generation is very low at nuclear plants. However, while marginal costs hour-to-hour are low, fixed operating costs (e.g., keeping employees on staff) are high. Total operations and maintenance (O&M) costs at U.S. nuclear plants have increased almost 20 percent in real terms since 2002 and today are more than twice as high as O&M costs at natural gas plants. These higher costs reflect nuclear plants' substantially higher requirements for safety, security, and testing.

In this paper, we use evidence from a nuclear power plant closure to examine the rapidly evolving economics of nuclear power and to assess the potential private and social consequences of plant closures. While in operation, the San Onofre Nuclear Generating Station (SONGS) generated an average of 16 million megawatt hours of electricity annually, making it the second largest electric generating facility in California. During this period, SONGS generated enough electricity to meet the needs of 2.3 million California households[2] – about 8 percent of all electricity generated in the state. SONGS was closed abruptly in February 2012, when workers discovered problems with the plant's steam generators. Although it was not known at the time, SONGS would never operate again.

The first-order effect of the plant's exit was a large inward shift of the electricity supply curve. Like other nuclear power plants, SONGS produced electricity at very low marginal cost. Consequently, the plant was always near the bottom of the supply curve, operating around the clock and providing a consistent source of electricity. When SONGS was closed, this generation had to be made up for by operating other generating resources with higher marginal cost. We use rich micro-data from a variety of sources and a novel econometric method to identify which

[1]Peak wholesale prices at various hubs for ICE contracts; source: EIA. Prices throughout are deflated to 2013 dollars using the GDP deflator.

[2]U.S. DOE/EIA "Electric Sales, Revenue, and Average Price," November 2013, Tables T1 and T2. California households used an average of 6.9 megawatt hours in 2012.

generating resources increased production. We find that the lost generation from SONGS was met largely by in-state natural gas plants. Bringing these additional plants online cost an average of $63,000 per hour in the twelve months following the closure. The SONGS closure also had important implications for the environment, increasing carbon dioxide emissions by 9 million tons in the first twelve months. To put this in some perspective, this is the equivalent of putting 2 million additional cars on the road.[3]

There was also a second-order, but not insignificant, additional impact on the market. SONGS was even more valuable than these numbers suggest because of its location between Los Angeles and San Diego, two enormous demand centers. Although there is transmission that connects Southern California to the rest of the state, the capacity is limited. Prior to the closure, transmission capacity between Northern and Southern California was almost always sufficient, so that wholesale prices equalized in the two regions during the vast majority of hours. However, beginning with the closure in 2012, we document a substantial divergence in prices between Northern and Southern California. This binding transmission constraint and other physical constraints of the grid meant that it was not possible to meet all of the lost output from SONGS using the lowest cost available generating resources.

These second-order effects are reflected in our model as "residuals," measured as deviations from predicted plant behavior. We find that during low demand hours, the change in generation closely follows predictions based on pre-closure behavior, with about half of the increased generation coming from Southern California and the other half coming from Northern California. During high demand hours, however, we find significant residual effects: higher cost generating units coming online more than predicted. In high demand hours in 2012, we find that as much as 75 percent of the lost generation was met by plants located in Southern California. On average, the deviations from predicted behavior increased generation costs by $4,500 per hour, implying that the total cost of additional natural gas generation was almost $68,000 per hour in the twelve months following the closure.

These residuals also potentially reflect non-competitive behavior. Tight market conditions make it more profitable for certain firms to exercise market power, and using our model we are able to determine which individual plants changed their behavior the most after the SONGS closure. Because of the transmission constraints, the largest positive residuals are at Southern plants, and the largest negative residuals are at Northern plants. Surprisingly, we also find large negative residuals during high demand hours at two Southern plants: Alamitos and Redondo, both owned by the same company. This was unexpected but, as it turns out, not coincidental. The Federal Energy Regulatory Commission recently alleged market

[3] According to U.S. DOE/EIA Annual Energy Review, September 2012, Table 2.8 "Motor Vehicle Mileage, Fuel Consumption, and Fuel Economy", light-duty vehicles with a short wheelbase use an average of 453 gallons of gasoline annually. For each gallon of gasoline, 19.6 pounds of carbon dioxide are emitted.

manipulation at these plants over the period 2010 to 2012, for which JP Morgan paid fines of over $400 million. The fact that the results clearly identified these two plants suggests that our approach may serve as a useful diagnostic tool. Although a large residual effect does not prove that a plant is exercising market power, it is a good indicator of unusual behavior.

Overall, we find that the SONGS closure increased generation costs at other plants by $350 million during the first twelve months. This is a large change, equivalent to a 13 percent increase in total in-state generation costs. Annual O&M costs at SONGS were about the same amount, so the decision to close probably made sense from a private perspective. Incorporating externalities makes it less clear. Our estimates of the increase in carbon dioxide emissions imply external costs of almost $320 million during the first twelve months. If plant closure decisions are to be made efficiently, it is important that these environmental impacts be taken into account. Historically, state and federal policies aimed at decreasing carbon emissions have not been designed to incentivize nuclear plants.

Our paper contributes to several strands of the literature. Several recent papers have focused on the prospects for nuclear power, particularly as concern about climate change has increased (Joskow and Parsons, 2009; MIT, 2009; Davis, 2012; Joskow and Parsons, 2012; Linares and Conchado, 2013). However, the literature has almost exclusively focused on the outlook for *new* nuclear plants. The decision to enter the market is quite different from the decision to exit. Entry decisions are driven in large part by construction and financing costs, which historically have been very high for nuclear plants. In contrast, because these costs are sunk for existing nuclear plants, exit decisions are driven by wholesale electricity prices and operating expenses. With construction of new nuclear almost completely halted, we argue that exit will be the more policy-relevant margin for the foreseeable future.

Our paper also adds to a small literature on the value of geographic integration in electricity markets (Mansur and White, 2012; Birge et al., 2013; Wolak, 2014*a*; Ryan, 2014). Economists have long written about the importance of transmission constraints, but previous studies have either used stylized theoretical models (Cardell, Hitt and Hogan, 1997; Joskow and Tirole, 2000), or Cournot simulations (Borenstein, Bushnell and Stoft, 2000; Ryan, 2014), rather than econometric analysis. Our methodology is novel, because it quantifies the impact of transmission constraints without requiring strong assumptions about the firms' objective function or an explicit representation of the physical constraints of the electric grid. While our estimates are not directly applicable to other markets, we see broad potential for applying this general method elsewhere. Our approach relies entirely on publicly-available data, so it would be relatively straightforward to perform similar analyses in other markets, both for quantifying the impacts of large changes in generation and transmission infrastructure, and for detecting unusual changes in firm behavior.[4]

2 Background

2.1 Economic Outlook for Existing Nuclear Plants

In the United States, electricity generation in 2012 came from coal (37%); natural gas (30%); nuclear (19%); hydro (7%); and wind, solar and other renewables (5%).[5] The global generation mix was qualitatively similar: fossil fuels (67%); nuclear (11%); hydro (17%); and wind, solar, and other renewables (5%).[6] This mix of technologies reflects marginal and fixed cost considerations, flexibility, and environmental objectives. The lowest marginal cost sources are solar and wind, followed by nuclear, and then by fossil fuel plants. Coal tends to have lower marginal cost than natural gas; but in recent years, falling natural gas prices in North America have pushed some natural gas plants ahead of coal plants in the queue (Cullen and Mansur, 2014; Holladay and LaRiviere, 2014; Linn, Muehlenbachs and Wang, 2014).

Despite the low marginal cost of nuclear plants, their profitability and long-term viability have eroded substantially since 2009 in the United States (EIA 2014). Four nuclear plants have recently closed: Crystal River, Kewaunee, San Onofre, and Vermont Yankee. Moreover, recent reports have flagged numerous additional plants that are at risk of closing (Navigant Consulting Inc, 2013; UBS, 2013, 2014). One report provided the following summary: "Nuclear units, with their high dispatch factors have among the greatest exposure to gas/power price volatility, as they are price takers. In tandem, nuclear generators have continued to see rising fuel and cost structures of late, with no anticipation for this to abate" (UBS, 2013). As a result of these concerns, the EIA assumes 6 GW of nuclear retirements by 2019 in the reference case for its 2014 Annual Energy Outlook.

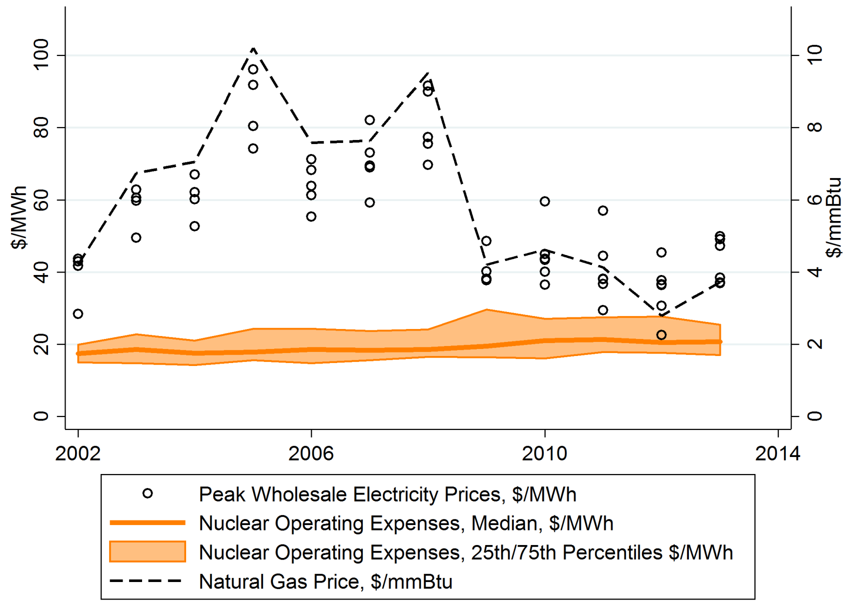
Figure 1 describes this erosion of profitability, showing in real terms both rising costs (solid orange line) and falling wholesale electricity prices (hollow circles, for peak prices). Even during peak hours, nuclear plants are currently earning only modest net revenues. The primary driver has been a dramatic decrease in wholesale electricity prices. This is a direct consequence of the fall in natural gas prices (the dashed line in Figure 1) driven by the shale boom. The advance of technologies for extracting unconventional natural gas caused an almost

[4]Such large changes are not uncommon. For instance, the current California drought has led to hydroelectric generation levels in 2014 that are over one million MWh per month lower than the 2005-2013 averages, a drop roughly equal to the loss in generation from SONGS. As another example, Germany has closed 6 of 17 nuclear power plants (6.3 total gigawatts) since the Fukushima accident in March 2011 (Grossi, Heim and Waterson, 2014).

[5]Table 7.2a "Electricity Net Generation: Total (All Sectors)" in EIA (2013).

[6]EIA's International Energy Statistics, 2012.

Figure 1: Declining Profitability of U.S. Nuclear Power Plants



Note: This figure plots wholesale peak electricity prices in real $/MWh at various ICE hubs around the country. The dashed black line shows Henry Hub natural gas prices (in $/mmBtu), the driver of wholesale peak electricity prices. The orange lines show the median, 25th percentile, and 75th percentile operating expenses at U.S. nuclear plants, in real $/MWh. Electricity and natural gas prices are from EIA; operating expenses are from EUCG, Inc.

50 percent decline in natural gas prices in the United States from 2007 to 2013 (Hausman and Kellogg, 2015). Natural gas power plants are frequently on the marginal portion of the supply curve, so their marginal costs tend to set wholesale electricity prices. Moreover, marginal costs for natural gas plants are predominantly fuel costs. Accordingly, not only are natural gas plants pushing ahead of coal plants in the supply queue, they are also pushing down wholesale electricity prices.[7] The magnitude of the pass-through, empirically estimated in Linn, Muehlenbachs and Wang (2014), is determined by the heat rates of marginal plants.

Two additional factors help explain this period of sustained low wholesale electricity prices. First, there has been a rapid rise in renewables capacity. Non-hydro renewables grew by over 250 percent from 2001 to 2013, albeit from a small baseline. Second, electricity demand has been largely stagnant. While growth averaged almost 4 percent per year from 1970 to 1990, from 2000 to 2014 it averaged less than 1 percent per year,[8] and it is expected to continue to be less than 1 percent per year (EIA 2015). As a result of falling natural gas prices, growing

[7] The figure plots peak wholesale prices, using annual averages of daily prices for ICE contracts at the MISO (Indiana Hub), PJM (West), CAISO (NP-15), Northwest (Mid-Columbia), CAISO (SP-15), and Southwest (Palo Verde) hubs. The year-to-year variation largely reflects changing natural gas prices. The geographic dispersion reflects transmission constraints in electricity combined with pipeline constraints in natural gas and differences in heat rates at natural gas plants.

[8] U.S. DOE/EIA "Table 7.6 Electricity End Use," April 2015.

renewables capacity, and stagnant demand, both peak and off-peak electricity prices fell by around 50 percent in real terms from 2007 to 2012.[9]

At the same time that revenues have fallen, multiple factors have contributed to rising costs at nuclear power plants. Costs can be divided into three categories: (1) capital costs, (2) fuel costs, and (3) operating expenses. Capital costs are largely sunk, and therefore not relevant for our analysis. Fuel costs per MWh, however, increased in real terms by 25 percent from 2002 to 2012, concurrent with an increase in uranium prices.[10] Operating expenses have also increased 18 percent in real terms from 2002 to 2012 at the median plant.[11] Part of this increase has come from rising labor costs. According to data from the Bureau of Labor Statistics' *Quarterly Census of Employment and Wages*, average annual salaries in the nuclear electric power generation sector (NAICS 221113) increased by 21.5 percent in real terms between 2002 and 2013. Possible additional factors include new safety requirements following Fukushima and the aging of U.S. reactors. In 2014, the age of U.S. nuclear power reactors ranged from 19 to 46 years, and the average age was 35.

Figure 1 shows that operating expenses at U.S. nuclear plants have increased steadily since 2002. This is true whether one looks at the median, 25th, or 75th percentile. These expenses include operations and maintenance costs, such as labor costs, but not fuel costs or capital expenditures. A substantial wedge between peak wholesale prices and operating costs can be seen in the early 2000s, but by 2009 the wedge was dramatically shrunk. Moreover, the actual wedge between revenues and costs is even lower than what is shown in this figure. Off-peak wholesale electricity prices are also relevant, and are around 35 percent lower than on-peak prices. Fuel costs also reduce the wedge; in 2012 they were around \$7–8 per MWh (source: EIA Table 8.4, and SNL). Unfortunately, we do not have a comprehensive time series of nuclear fuel costs.

The figure makes clear that U.S. nuclear power plants have become much less profitable. Nuclear plants continue to have lower marginal cost than coal and gas plants and thus are still near the bottom of the supply curve. Instead, what has changed is the ability of hour-to-hour

[9] In addition to the peak prices for ICE contracts available from EIA, we assembled data from SNL Financial from 6 different wholesale hubs: ERCOT (North), New England ISO (Massachusetts Hub), PJM (West), Southwest (Palo Verde), Northwest (Mid-Columbia), and MISO (Illinois Hub). Off-peak prices generally run from about 11pm to 7am, though the exact hours vary across ISO. In both 2007 and 2012, off-peak prices averaged around 65 percent of peak prices.

[10] Source: EIA, "Table 8.4. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, 2002 through 2012." Data are not available for independent power producers, but fuel costs are presumably similar as all plants purchase fuel assemblies in the same market.

[11] Source: EUCG, Inc. EUCG assembles blinded cost data from all nuclear power plants in the U.S. for cross-reactor information sharing. These data are not publicly available, but we were provided with summaries by quartiles after making a data request. Other sources of information on operating costs include FERC and EIA, which only collect data on a subset of plants, or SNL, which extrapolates the FERC data to other plants. The EUCG data, which represent *all* plants, are in line with FERC and SNL summaries.

net revenues to cover the fixed costs of keeping a nuclear plant open. Of course, all types of electric-generating facilities must be able to cover their ongoing fixed costs, but this is particularly relevant for nuclear power plants because of their high O&M costs. Table 1 shows fuel and O&M costs at nuclear plants compared to other forms of generation. Nuclear plants have by far the lowest fuel cost. However, O&M costs are $15.8/MWh at nuclear plants, compared to $3.9–$9.4/MWh at fossil-fuel plants.[12] Natural gas combined cycle plants, in particular, have O&M costs that are only about 1/4th that of nuclear plants.

Although in the table we have expressed O&M costs scaled by generation, this should not in general be thought of as a marginal cost. With O&M, it is difficult to sharply distinguish between fixed and marginal costs; the former consists of costs that allow a plant to remain open, but do not depend on the level of generation produced. These include, for instance, employees whose primary task is safety compliance. In Table 1, we do not attempt to distinguish the two types of O&M. What is most noteable, however, is how much higher O&M costs are at nuclear plants relative to coal and natural gas plants. As such, fuel makes up less than 35 percent of operating expenses for nuclear plants, while it makes up over 75 percent at coal and natural gas plants.

The table makes clear that the economics of running a nuclear plant are quite different from the economics of running a coal or natural gas plant. While low fuel costs mean that nuclear plants should be continually operating conditional on being open, high O&M costs mean that even running 365 days per year may not generate enough revenue if wholesale prices are low. These high O&M costs are not sunk in the way that construction costs are; they can be avoided if a plant closes, and indeed you would expect a plant to close when O&M costs exceed expected net revenue.[13]

2.2 The San Onofre Nuclear Generating Station

San Onofre Nuclear Generation Station (SONGS) is a retired two-reactor, 2,150 megawatt nuclear power plant, operated by Southern California Edison (SCE).[14] Trouble for SONGS started on January 31, 2012 when operators detected a small leak inside one of the steam generators. The reactor with the leak was shut down immediately. At the time this occurred, the other reactor had already been shut down for three weeks for a routine refueling outage. This routine refueling outage was scheduled at a time of year when demand was low and

[12] Average nuclear O&M costs are somewhat higher in EUCG data, but this is largely a function of weighting by generation. The unweighted average O&M costs in the SNL data are $20.4/MWh for 2013, compared to $20.8/MWh in the EUCG data.

[13] An additional cost, required by the NRC, is the decommissioning of a site after closure. The NRC requires funds for decommissioning in advance, for instance through a trust fund or other surety method.

[14] SCE is also the majority owner (78%). The other owners are San Diego Gas & Electric (20%) and the city of Riverside (2%).

Table 1: Fuel Costs and Operating Expenses by Electric Generating Technology, 2013

	Fuel, \$/MWh	O&M, \$/MWh	Fuel plus O&M, \$/MWh
Nuclear (n=99)	8.2	15.8	24.0
Coal (n=1074)	25.2	7.9	33.1
Natural Gas Combined Cycle (n=1764)	32.6	3.9	36.6
Natural Gas Combustion Turbine (n=2083)	41.7	9.4	51.1

Source: Authors' calculations based on data from SNL Financial's "Generation Supply Curve." The table reports mean fuel and operating costs per megawatt hour, weighted by net generation. Means are calculated over all generating units that were operating in the continental United States in 2013.

was intended to affect only one reactor. In this regard, it was like other planned temporary outages at nuclear plants, which are in general designed to limit disruption to the electricity market.

Although it was not known at the time, neither reactor would ever operate again. On investigation, it was discovered that thousands of tubes in the steam generators in both units were showing premature wear. This was followed by months of testing and, eventually, a proposal to the Nuclear Regulatory Commission (NRC) to restart one of the units at reduced power level. An additional eight months passed without a decision from the NRC. Meanwhile, policymakers grew concerned that without SONGS, the grid would face "additional operational challenges in the Los Angeles Basin and San Diego areas" (CEC 2012), relating to the possibility of insufficient summer capacity and the possibility of transmission constraints (CAISO 2012; NERC 2012).

Facing uncertainty about the NRC ruling, and continued costs of maintaining SONGS in a state of readiness, SCE made the decision in June 2013 to permanently retire the facility. "SONGS has served this region for over 40 years," explained Ted Craver, Chairman and CEO, "but we have concluded that the continuing uncertainty about when or if SONGS might return to service was not good for our customers, our investors, or the need to plan for our region's long-term electricity needs" (Southern California Edison, 2013).

The SONGS closure was abrupt, permanent, and unexpected; this allows us to sharply distinguish between the before and after periods, and thus to identify the effect of the closure. In contrast, in many empirical settings, openings and closings of transmission and generation capacity are both expected and endogenous, so that causal effects are difficult to identify. Moreover, outages at transmission and generating facilities are potentially endogenous, as they are more likely to occur when stress is being put on the system. SONGS is of additional interest because, like many U.S. nuclear power plants, it operated in a deregulated electricity market. In contrast, in states where generation companies are regulated using cost-of-service regulation there is less scope (and less incentive) for companies to exercise market power in response to changes in market conditions.

Finally, the SONGS setting is worth studying because it demonstrates the importance of accounting for transmission congestion. Transmission constraints are a pervasive feature of electricity markets, and they are extremely important because unlike most other goods, electricity cannot be cost-effectively stored. Supply must meet demand at all times, or the frequency in the grid will fall outside of a narrow tolerance band, causing blackouts. With electricity demand highly variable and inelastic, the market clears mostly on the supply side. Geographic integration helps smooth the price volatility that can result.

3 Data

For this analysis we compiled publicly-available data from a variety of different sources including the U.S. Department of Energy's Energy Information Administration (EIA), the California Independent System Operator (CAISO), and the U.S. Environmental Protection Agency (EPA).

3.1 Generation Data from EIA

We first assembled a dataset of annual plant-level electricity generation from the EIA. The advantage of these data is that they are comprehensive, including not only large fossil-fuel generating units, but also smaller and less frequently operated units, as well as hydroelectric facilities, solar and wind plants, and nuclear plants. Most California plants complete the survey only once per year, so we perform all analyses of the EIA data at the annual level, relying on the other datasets described below for within-year comparisons.

Table 2 describes California electricity generation in 2011 and 2012. By far the largest source of generation in California is natural gas, with 44 percent of total generation in 2011. The second largest source is hydro, accounting for 21 percent of generation. The two nuclear plants, San Onofre and Diablo Canyon, each contributed approximately 9 percent of total generation in 2011. Finally, geothermal, wind, solar, and other renewables account for about 14 percent of total generation. Additional details are provided in the Online Appendix.

SONGS was closed on January 31, 2012, so the columns in Table 2 can be approximately interpreted as before and after the SONGS closure. Panel A reports average monthly generation by fuel type. Nuclear generation decreased by 1.5 million megawatt hours monthly; this matches the drop in generation expected given the SONGS hourly capacity of 2,150 MW. The table also shows, however, that 2012 was a relatively bad year for hydroelectric power, with a decrease of 1.3 million megawatt hours monthly. Thus the year-on-year decrease in

Table 2: California Electricity Generation, 2011-2012

	Average Monthly Generation, Million MWh 2011	Average Monthly Generation, Million MWh 2012	Change
Panel A: By Generation Category, EIA Data			
Natural Gas	7.41	9.97	2.56
Wind	0.65	0.81	0.17
Solar (PV and Thermal)	0.07	0.12	0.04
Other Renewables	0.50	0.53	0.02
Geothermal	1.05	1.04	0.00
Coal	0.17	0.11	-0.05
Other Fossil Fuels	0.29	0.22	-0.08
Hydroelectric	3.54	2.28	-1.25
Nuclear	3.06	1.54	-1.51
Panel B: By Type of Natural Gas Plant, EIA Data			
Independent Power Producer Non-Cogen	2.63	4.48	1.85
Electric Utility	2.24	2.98	0.73
Industrial Non-Cogen	0.03	0.11	0.07
Commercial Non-Cogen	0.02	0.02	0.00
Commercial Cogen	0.14	0.13	-0.01
Independent Power Producer Cogen	1.37	1.36	-0.01
Industrial Cogen	0.99	0.90	-0.09
Panel C: By Generation Category, CAISO Data			
Thermal	6.12	8.47	2.35
Imports	5.45	5.77	0.32
Renewables	2.11	2.25	0.14
Large Hydroelectric	2.47	1.58	-0.89
Nuclear	3.07	1.55	-1.51

Note: This table reports the average monthly net electricity generation in California in 2011 and 2012, measured in million MWh. The EIA data describe all U.S. generating facilities with more than one megawatt of capacity. We include generation from all facilities in California. In Panel A, "Other Renewables" includes wood, wood waste, municipal solid waste, and landfill gas. "Other Fossil Fuels" includes petroleum coke, distillate petroleum, waste oil, residual petroleum, and other gases. Panel C describes electricity sold through the California Independent System Operator, including four categories of generation from inside California, and "imports" which includes all electricity coming from out of state.

hydroelectric generation is almost as large as the lost generation from SONGS. Offsetting these decreases, natural gas generation in California increased by 2.6 million megawatt hours monthly. There is also a modest increase in wind generation, and close to zero changes for all other categories.

Panel B examines natural gas generation more closely. These categories primarily distinguish between whether plants are owned by electric utilities or independent power producers, and whether or not the plants are cogeneration facilities. The two largest categories are "Independent Power Producer Non-Cogen" and "Electric Utility." Both increase substantially in

2012. Generation is essentially flat in all other categories between 2011 and 2012. In some cases (e.g. industrial non-cogen) there are large percentage changes but from a small base level. It is difficult to make definitive statements based on these aggregate data, but this is consistent with plants in these other categories being much less able to respond to market conditions. With industrial, commercial, and cogeneration facilities, electrical output is a joint decision with other processes (e.g. oil extraction or refining, steam production, etc.), which limits the ability of these plants to respond quickly to changes in market conditions.

3.2 Generation Data from CAISO

To complement the EIA data, we next assembled a database using publicly-available records from CAISO. The CAISO data describe hourly electricity generation by broad categories (thermal, imports, renewables, large hydroelectric, and nuclear). The renewables category is disaggregated into six subcategories (geothermal, biomass, biogas, small hydroelectric, wind, and solar). See CAISO (2013c) for details. Table 2, Panel C describes generation by category in 2011 and 2012. These data corroborate the general pattern observed in the EIA data. From 2011 to 2012, there is a large increase in thermal generation and large decreases in nuclear and hydroelectric generation.

An important advantage of the CAISO data is that they also track imports. Between 2011 and 2012 imports increased from 5.45 to 5.77 million megawatt hours monthly. This is a substantial increase, but it offsets only 1/5th of the shortfall experienced from the SONGS closure, and only about 1/10th of the combined shortfall from SONGS and the decrease in hydroelectric generation. We examine the role of imports in greater depth in Section 5.1, but both the EIA data and CAISO data suggest that California thermal generation played the primary role in making up for the lost generation from SONGS.

3.3 Generation Data from CEMS

We next built a database of hourly emissions, heat input, and electricity generation by generating unit using the EPA's Continuous Emissions Monitoring System (CEMS). CEMS data have been widely used in economic studies of generator behavior because they provide a high-frequency measure of generation at the generating unit level. See, e.g., Joskow and Kahn (2002); Mansur (2007); Puller (2007); Holland and Mansur (2008); Cullen (2013); Cullen and Mansur (2014); Graff Zivin, Kotchen and Mansur (2014); Novan (Forthcoming). CEMS data are highly accurate because facilities must comply with specific requirements for maintenance, calibration, and certification of monitoring equipment, and because the methodology used for imputing missing data creates an incentive for generating units to keep monitoring equipment online at all times.

During our sample period, 107 plants in California report to CEMS. In 2011, these plants represent 30 percent of total generation in California and 62 percent of total natural gas generation. This relatively low fraction of generation covered by CEMS reflects that a large share of California generation comes from nuclear, hydro, and renewables – none of which are in CEMS. In addition, one third of natural-gas fired generation in California is from cogeneration, industrial, and commercial facilities, which are generally not in CEMS. Indeed, generation reported in CEMS in 2011 is 96 percent of non-cogen natural gas-fired generation by electric utilities and independent power producers reported in the EIA data.

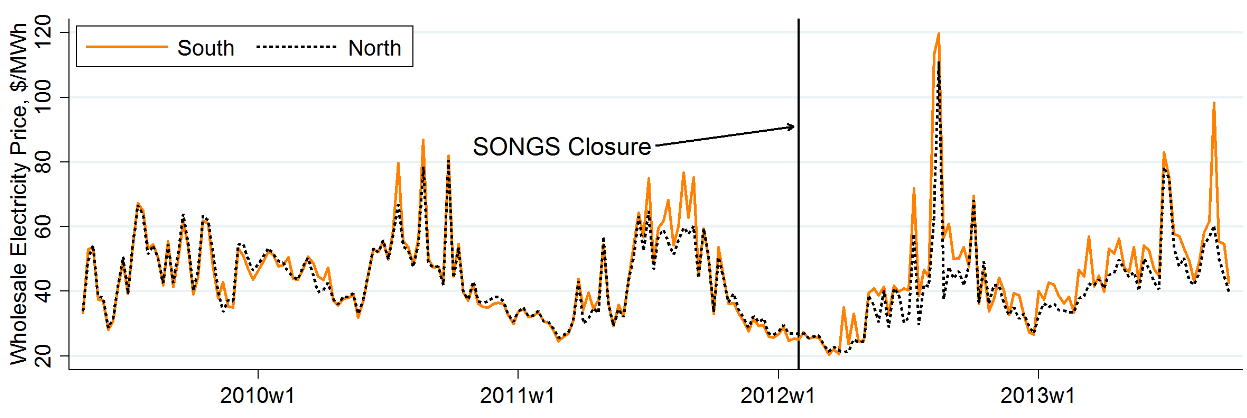
Despite the incomplete coverage, the CEMS data are extremely valuable. They cover the largest thermal plants and the plants that are best able to respond to market changes, in addition to being the only publicly available information on hourly, generating unit-level outcomes. Moreover, by combining the CEMS data with EIA and CAISO data, we are able to get a sense of how much our results might be affected by focusing exclusively on CEMS generating units. The Online Appendix lists the largest plants that do not appear in CEMS. Overall, these plants tend to be quite small, or to be types of facilities (e.g. cogeneration plants, industrial facilities) that are not able to respond quickly to market changes. We empirically examine the responsiveness of these units below.

While CEMS data describe gross generation, for this analysis we would ideally observe net generation. The difference between the two is equal to "in-house load," which is the electricity the plant uses to run, for instance, cooling equipment or environmental controls. As such, net generation is what is sold on the grid. Reliable plant-level or unit-level estimates of the ratio between net and gross generation are not available. In the analyses that follow we use an implied measure of net generation, which we calculate as 95.7 percent of gross generation; details are in the Online Appendix.

3.4 Wholesale Price Data

We also obtained hourly wholesale electricity prices from CAISO. We use prices at three locations: NP15 (Northern California), ZP26 (Central California), and SP26 (Southern California). Figure 2 plots prices in Northern and Southern California in dashed black and solid orange lines, respectively. We plot prices for 4 p.m. on weekdays (averaged across the week), a time when transmission constraints are more likely to bind. Before the SONGS closure, prices track each other extremely closely, and the price differential is not statistically significant (p-value 0.1). After the SONGS closure, prices diverge and the price differential is positive (i.e. South exceeds North) and statistically significant (p-value <0.01). There are even a few weeks with differentials that exceed 50 percent of the North price. Also, the corre-

Figure 2: Evidence of Increasing Transmission Constraints since 2012



Note: This figure was constructed by the authors using data on California wholesale electricity prices from CAISO. The figure plots average weekly prices at 4 pm between May 2009 and September 2013, in $2013/MWh. Weekends are excluded. The dashed black line is for Northern California (NP15), and the solid orange line is for Southern California (SP26). The vertical line indicates January 31, 2012, the day the second SONGS unit was shut down.

lation between Northern and Southern prices falls, from 0.94 in the pre-period to 0.89 in the post-period.

4 Empirical Strategy and Generation Regressions

The data show a significant increase in natural gas generation between 2011 and 2012. We next ask how much of this increase is due to the SONGS closure, and whether any other generating resources changed production in 2012 as a result of the closure. To answer these questions, we need a model which can tell us which generating units are *marginal* at any point in time. Low-cost generating units operate most hours of the year, regardless of system-wide demand, while higher-cost generating units operate only during relatively high demand hours. System-wide demand varies substantially hour-to-hour as a function of weather and economic activity, and different units turn on and off across hours to equate supply with demand. We describe this relationship semi-parametrically, using a series of regressions, estimated separately before and after the closure.

We distinguish between two effects: (1) the predicted change in generation associated with the next generating units along the marginal cost curve being brought online; and (2) the residual change in generation associated with a change in the order of the generating units along the supply curve. The predicted effects, which vary from hour to hour, measure a non-marginal shift (arising from the loss of SONGS) in the net demand faced by each generating unit. Residual effects measure differences between actual generation and predicted generation, reflecting transmission constraints and other physical limitations of the grid as well as non-competitive behavior.

An alternative to our empirical strategy would have been to simulate counterfactuals using an engineering model of the electrical grid combined with a structural model of firm optimization. Although these models have been widely used, our method is better suited to the application we consider for several reasons. First, while Cournot simulations have been used to study two-node transmission problems, the transmission constraints in our application are more complex. In addition to congestion between the two main North and South zones, congestion *within* regions is also important. And while engineering models exist that attempt to capture these features (e.g. GE-MAPS), they assume more information than market participants actually have, and they rely on simplifying assumptions that do not reflect changing grid conditions (Barmack et al., 2006). In practice, electric grid system operators use a combination of output from such models and real-time information about system conditions.

Performing counterfactual simulations would also require strong assumptions about generator and system operator behavior. While the objective function for independent power producers is relatively clear, describing behavior by investor-owned utilities is more difficult because they are subject to rate-of-return regulation. System operator behavior is important as well. During this period, CAISO was actively implementing new automated bid mitigation procedures and increasing the use of exceptional dispatches (CAISO 2013b).[15] Modeling these rapidly evolving market practices explicitly poses real challenges and would have required not only imposing these constraints in the model but also making strong assumptions about generators' expectations about these practices.

4.1 Generation Regressions by Category

The core of our econometric model is a system of what we call "generation regressions," which describe the relationship between system-wide demand and generation at individual sources. We estimate these regressions first for broad categories of generation and then, in Section 4.2, for individual generating units. For the generation regressions by category the estimating equation takes the following form:

$$generation_{it} = \sum_{b} (\gamma_{bi} \cdot \ \mathbb{1}\{system\text{-}wide\ demand_t = b\}) + \varepsilon_{it}. \tag{1}$$

The dependent variable is electricity generation for category i in hour t, measured in megawatt hours. We use the categories reported in CAISO data: thermal, large hydro, imports, nuclear, and renewables. In addition, we separate thermal into generation that appears in CEMS and generation that does not, where the latter is calculated as the difference between thermal

[15]Bid mitigation is the replacement of submitted bids with default cost-based bids; exceptional dispatch is a manual override of the market optimization algorithm.

generation reported by CAISO and thermal generation reported by CEMS.

The only independent variables in the regression are a set of indicator variables corresponding to different levels of total system demand. We divide system-wide demand into bins of equal width, indexed by b. For convenience, we define the bin width as 2,150/2 = 1,075 megawatt hours, so that we can assume that system demand increased by two bins following the SONGS closure. We have experimented with alternative bin widths, and the results are similar with both more and fewer bins. We have also estimated several alternative models that include fixed effects, such as: (i) hour-of-day effects, (ii) month-of-year effects, and (iii) hour-of-day interacted with month-of-year effects. These could control for plant utilization that varies by time of day or by season. Results are very similar across specifications, indicating that these fixed effects add little to our preferred specification.

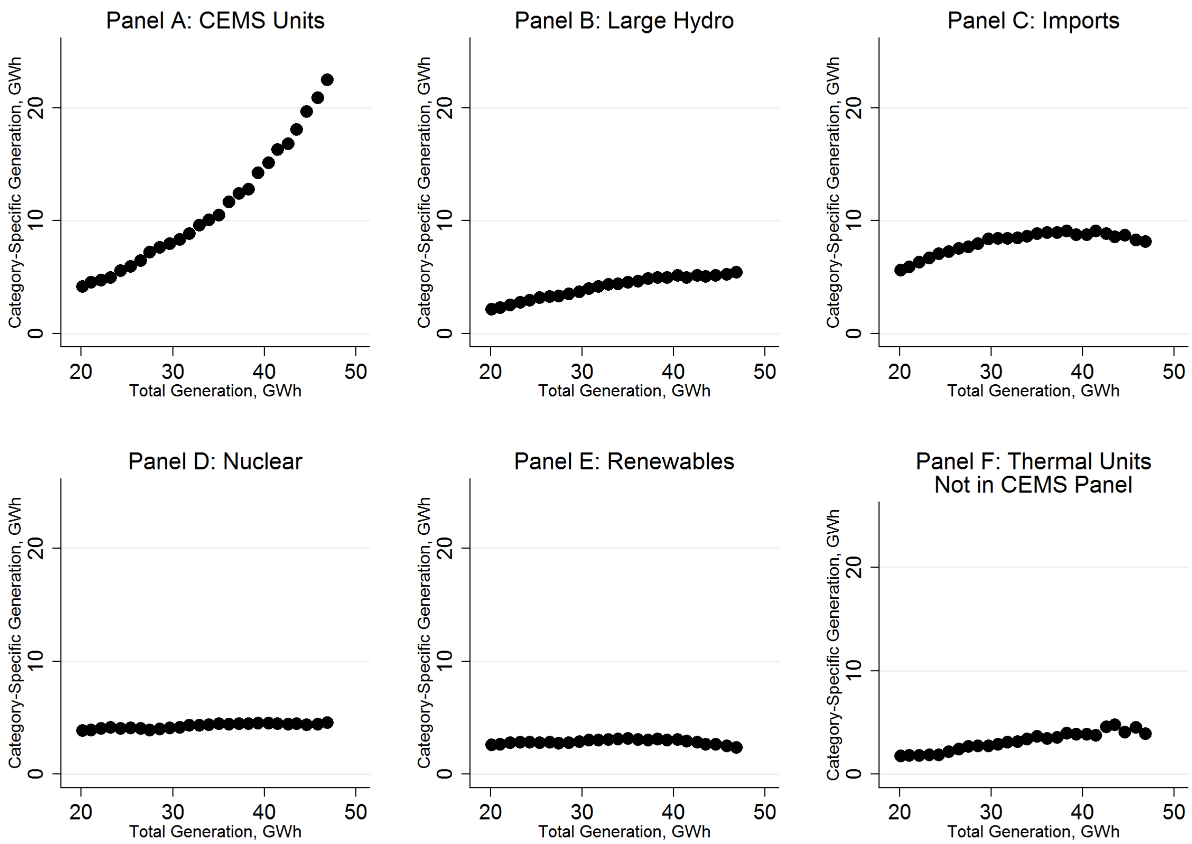
At first glance, this estimating equation would appear to suffer from simultaneity. However, electricity demand is both highly inelastic and highly variable across hours. In our sample, peak demand is routinely 150 to 200 percent of off-peak demand, and there is, in addition, rich seasonal variation in demand driven by lighting and air conditioning. In practice, these exogenous shifts in demand overwhelm cost shocks and other supply-shifters in determining equilibrium quantities.

We do not include a constant in the regression, as the indicator variables sum to unity. We could equivalently drop one indicator variable and interpret the coefficients relative to the excluded bin, but our approach makes it easier to interpret the estimated coefficients. Without including a constant, the coefficients γ_{bi} are equal to the average generation for category i when system demand is in bin b. If there were no dynamic dispatch considerations and no plant outages, this coefficient would be equal to zero up until the point when lower-cost generating units had already been turned on to meet demand, and then would be equal to the unit's capacity.

We estimate equation (1) using hourly data from 2010 through January 31, 2012, the two years leading up to the SONGS closure. We begin the sample on April 20, 2010 because hourly CAISO generation data are not available from before that date. Additionally, we drop a small number of days (fewer than ten) for which data from CAISO are incomplete. Because the coefficients γ_{bi} are allowed to differ by generation category, we estimate six separate regressions, one for each category. Figure 3 plots the estimated coefficients. In all plots, the x-axis is total generation from all sources, divided into bins. The y-axis is average source-specific generation in MWh. We plot all six categories using the same scale for the y-axis, so that one can immediately compare both the level and responsiveness of generation.

The CEMS units (Panel A) are very responsive across all quantiles of demand. Large-scale hydro (Panel B) is only somewhat responsive, which is a bit surprising given the potential for

Figure 3: Generation Regressions by Category



Note: These figures plot the coefficients from six separate regressions. The regressions are estimated using hourly data from April 20, 2010 until January 31, 2012. The x-axis is total generation from all sources, including imports, and the y-axis is average generation, in MWh, for that category of generation. For the non-CEMS thermal units in Panel F, we have subtracted total CEMS generation in our balanced panel from total thermal generation as reported by CAISO. The 95 percent confidence intervals are not shown, because they are extremely narrow for all six panels.

using large hydroelectric facilities to follow demand fluctuations.[16] We thought this might be because 2011 had relatively high water supply, so we also examined the generation regression for 2012. Though the overall level of hydro generation is lower in 2012, the slope is about the same. Imports (Panel C) are also somewhat responsive, but only for relatively low demand hours. This pattern is consistent with Bushnell, Mansur and Saravia (2008), which emphasizes results from a linear-log specification implying low import responsiveness during high demand hours. Past the median level of demand, imports are essentially flat. As we describe in the Online Appendix, this could result from correlated demand across states or from interstate transmission constraints. Nuclear (Panel D) and renewables (Panel E) are not responsive, as expected – the nuclear unit (Diablo Canyon) is baseload, and renewable generation is exogenously determined by weather. Thermal units not in the CEMS data (Panel F) are also

[16]However, hydro operators are subject to minimum and maximum flow constraints.

not very responsive, reflecting that they are primarily cogeneration and industrial facilities.

Comparing these results with the aggregate pattern of generation in Table 2, both show the ability of different generation sources to respond to changes in demand, albeit on very different time scales. The year-to-year comparison suggests that the majority of the response to the SONGS closure came from natural gas generation, and this is consistent with the hour-to-hour responsiveness observed in Panel A. Similarly, most of the other categories showed relatively little increase in 2012, and this accords with the lack of hour-to-hour responsiveness in Panels B–F. Finally, it is important to note that, while hydroelectric resources display some hour-to-hour variation in Figure 3, the year-to-year variation is entirely exogenous – it depends on total precipitation.

4.2 Unit-Level Generation Regressions

The generation regressions by category give a valuable overview, but they provide no detail about which particular plants tend to be the most responsive to system-wide demand, nor about the geographic location of production. Therefore, we next estimate generation regressions for each unit that appears in the CEMS data. The estimating equation for these regressions is very similar to equation (1) except the unit of observation is now the individual generating unit j,

$$generation_{jt} = \sum_{b} (\alpha_{bj} \cdot \mathbb{1}\{system\text{-}wide\ thermal\ generation_t = b\}) + e_{jt}. \tag{2}$$

The right-hand side bins, again indexed by b, are now defined over total generation by all the CEMS units in our balanced sample. We use this rather than total system demand because we want to identify the ordering within the category of natural gas units, and because we want to attribute changes from the pre-period to the post-period only to the SONGS outage, not to concurrent changes to renewables, hydro, or demand. Simultaneity is again not a concern: system-wide thermal generation is driven by exogenous shifts in electricity demand, which is both highly inelastic and highly variable across hours, and by idiosyncratic fluctuations in generation from renewables, hydro, and other non-CEMS categories of generation. We further examine this exogeneity assumption in the Online Appendix.

We estimate these unit-level generation regressions using two separate samples corresponding to before and after the SONGS closure. Observing behavior before the closure allows us to construct a counterfactual for what would have occurred if SONGS had not closed. For the pre-period, we again use data from April 20, 2010 to January 31, 2012, the year and a half leading up to the SONGS closure. For the main analysis we exclude generating units that enter or exit during our sample period, focusing only on continuously-operating generating units plus Huntington Beach units 3 and 4, which operated through most of our sample period, but were converted to synchronous condensers in January 2013.[17] We explore entry and exit in the Online Appendix, finding that excluding the units that enter or exit during our sample period is unlikely to bias our results.

Sample graphs of the coefficients from these pre-period unit-level regressions are shown in Figure 4. We show twelve plants: the four largest plants for each of three technologies. As can be seen in Panel A, the combined cycle plants tend to turn on, and even reach capacity, at fairly low levels of system demand. These units are generally new, large, and efficient. The combustion turbines in Panel B are turned on at higher levels of demand and have much smaller capacity. Finally, the boilers (Panel C), which are generally large and old, are turned on only at high levels of system demand.

For the post-period, we use data from February 1, 2012 through January 31, 2013. These are the first twelve months after the SONGS closure. While it would be interesting to examine longer-run changes in the market, this gets difficult to identify because the market is changing over time, both endogenously as costly transmission investments are made in response to the SONGS closure, and exogenously as, for example, new generation sources come online.[18]

When estimating the standard errors, we cluster by sample month to allow for arbitary spatial correlation and serial correlation within sample month. To examine whether this approach sufficiently accounts for serial correlation, we regressed the residuals on their lags. Beyond fifteen days, the estimated coefficients are close to zero and not statistically significant.

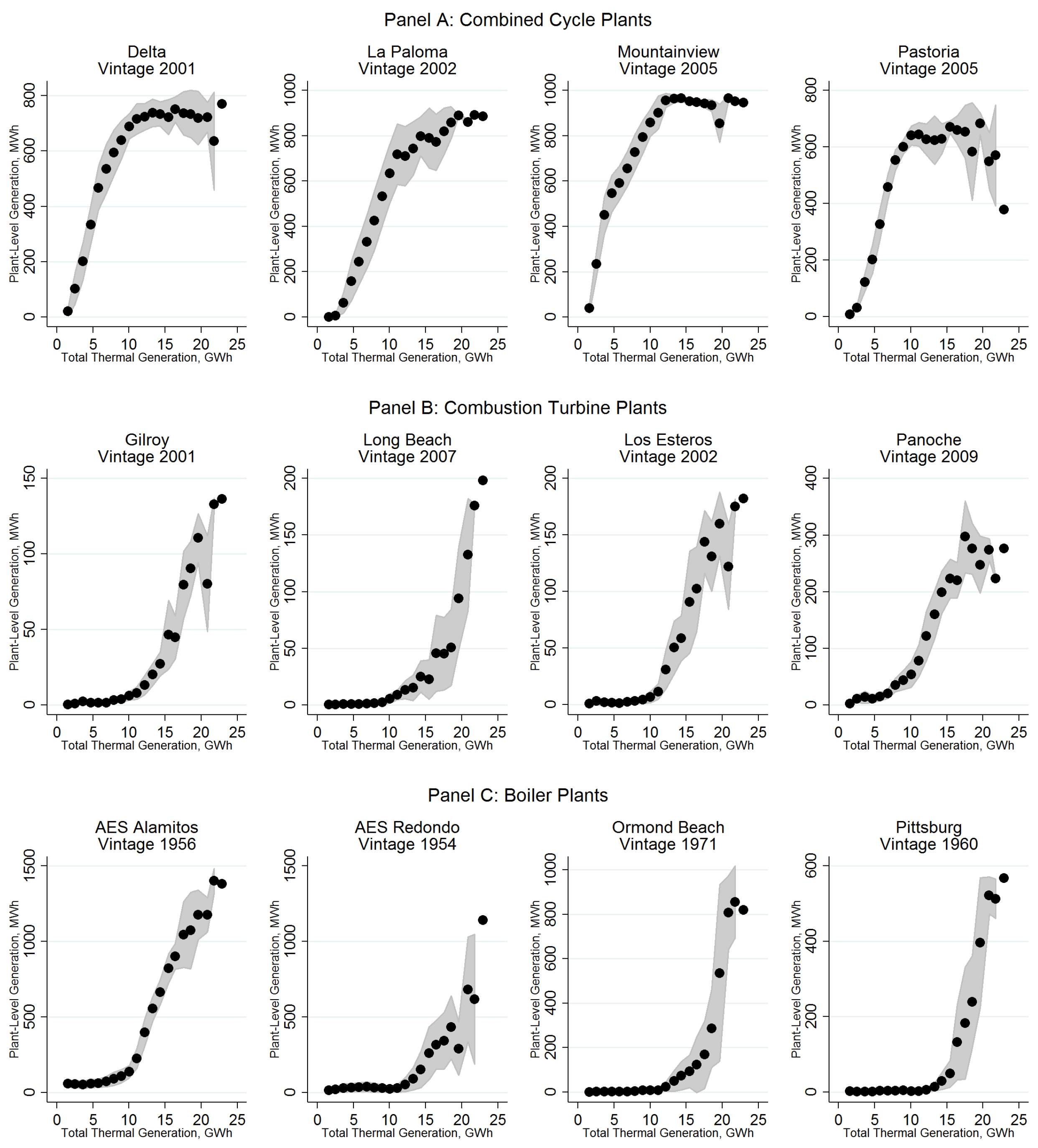
4.3 Predicted and Residual Effects

We thus have a set of coefficients α for each of 21 bins at 184 generating units in 2 time periods, for a total of over 7,000 coefficients. We summarize these estimates using what we call "predicted" and "residual" effects. For each generating unit, we define the predicted change in generation caused by the SONGS closure as follows: maintaining the coefficients from the pre-period, while requiring an additional 2,150 megawatt hours of generation to fill the SONGS gap. This is akin to assuming that the ranking of marginal costs did not change. Recalling that the width of each bin is equal to 1,075 megawatt hours, the predicted change (induced by the SONGS closure) across all bins b and all generating units j in a geographic

[17] We also drop four generating units which are owned by the Los Angeles Department of Water and Power (LADWP). LADWP maintains its own electricity generation and also imports power from other states through long-term contracts, and it is not part of the CAISO market.

[18] In the Online Appendix, we include results estimated with a post-period which goes through June 30, 2013, and the estimated residual effects results are similar but somewhat attenuated. This is exactly what one would expect as investments in new transmission capacity begin to relieve the constraint.

Figure 4: Generation Regressions by Individual Plant



Note: These figures plot the coefficients from 12 separate plant-level generation regressions, for the four largest plants within three technology types as indicated in the panel headings. The regressions are estimated using hourly data from April 20, 2010 until January 31, 2012. The x-axis is total generation from all plants in the CEMS panel and the y-axis is average generation, in MWh, for that individual plant. The grey areas show 95 percent confidence intervals, where standard errors are clustered by sample month. The scaling of the y-axis differs across plants, reflecting differing plant capacities.

region (J_{North} or J_{South}) is equivalent to moving up two bins:

$$\sum_{b>2} \sum_{j \in J} \left(\alpha_{bj}^{pre} - \alpha_{b-2,j}^{pre} \right) \cdot \theta_b^{post} \tag{3}$$

where θ_b^{post} is the fraction of hours that system-wide demand was in bin b during the post-period.[19]

Thus we are predicting how generating units will behave after the SONGS closure, modeled as a non-marginal shift in the net demand that each unit faces. Each unit's generation regression is identified using hour-to-hour variation, but the predicted effect of the SONGS closure is a shift in the entire distribution of net demand. The hourly variation is important, because as total demand varies tremendously across time, so does the impact of the closure on the behavior of individual generating units.

The residual effect we measure is the change in generation from the pre-period to the post-period, conditional on a given level of system demand:

$$\sum_{b} \sum_{j \in J} \left(\alpha_{bj}^{post} - \alpha_{bj}^{pre} \right) \cdot \theta_b^{post}. \tag{4}$$

Whereas the predicted effect models how a unit's behavior changes when the net demand that it faces increases, the residual effect measures how the unit's behavior changes conditional on a given level of net demand. Residual effects can be positive or negative, reflecting whether units are operating more or less than would be predicted from pre-period behavior. In the analysis that follows, we discuss potential drivers of these residual effects, as well as their impact on the cost of electricity generation.

Perhaps the most important drivers of residual effects are transmission constraints. Because SONGS was located in a load pocket, its closure led to binding physical constraints on the grid. To examine the broad pattern of transmission congestion, we begin by presenting results by region. Additionally, we evaluate the predicted and residual changes for subsets of hours when transmission constraints are most likely to bind. We consider two such subsets, each totaling approximately five percent of hours. First, we define weekday summer afternoons as 2 p.m. to 5 p.m. in months June through September. Second, we define high demand hours when total CEMS generation was in at least the 13th quantile (greater than 13,837 MWh); this leaves approximately the same number of observations as in the weekday summer afternoon results. We verify that both definitions are correlated with congestion as defined by the price differential between North and South. They are also correlated with one

[19] Note that this cannot be calculated for levels of thermal generation without a pre-period counterfactual, i.e. $b = 1$ and $b = 2$. In our sample, these levels of thermal generation do not appear in the post period, so in practice this is not an issue.

another, with a simple correlation of 0.30.

To attribute these residuals to the SONGS closure, the identifying assumption is that the ordering of units along the marginal cost curve in 2012 would have been the same as in 2010 and 2011, had SONGS not closed. There are many reasons to think this is a reasonable assumption. These are all natural gas plants, so there is no inter-fuel substitution, and the ordering among plants is essentially a monotonic ordering by heat rate.[20] Moreover, while there was a significant decrease in hydroelectric generation in 2012, this would not have affected the ordering of the natural gas units and, if anything, would have made transmission constraints *less* likely to bind. In the Online Appendix, we explore these and several additional potential confounding factors in depth. Our approach is not a panacea. As with any before-and-after comparison, we cannot rule out the possibility that our estimates are affected by other factors that are changing in the market at the same time. We conclude, however, in examining each potential confounding factor carefully, that any bias is likely to be small in magnitude. Moreover, it is hard to envision any alternative explanation for the particular pattern of regional and temporal residual effects that we observe.

5 Main Results

5.1 Impact on the Regional Pattern of Generation

Table 3 describes the effect of the SONGS closure on the geographic pattern of generation in California during the twelve months following the closure. The reported estimates are average hourly changes in MWh. Panel A reports effects for all hours. The predicted change in generation is similar in the North and the South, with both regions predicted to increase generation by about 900 MWh per month. The Central California column represents many fewer plants, and accordingly a smaller predicted change (300 MWh). By design, the total predicted effect is approximately equal to 2,150 MWh, the lost generation from SONGS. This geographic pattern reflects where in the state thermal resources are located. Without any transmission constraints, our estimates imply that about 40 percent of the lost output from SONGS would have been produced by plants located in Southern California.

The residual estimates show the displacement of generation from Northern generating

[20] Our methodology would be less useful in markets where fuel price changes affect the dispatch order between different forms of generation. For example, in many U.S. markets natural gas combined cycle plants have been moving ahead of coal in the dispatch order (Cullen and Mansur, 2014). Our methodology could still be used in these settings, but only for identifying predicted changes within each fuel type. Moreover, our methodology implicitly assumes that generators face very similar fuel prices. As we show in the Online Appendix, this assumption is easily met in our context, but one could envision situations in which natural gas pipeline constraints and other bottlenecks would lead this to be violated.

Table 3: The Effect of the SONGS Closure on the Regional Pattern of Generation

	Average Hourly Change in Net Generation, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Predicted Change (MWh)	892	300	944
	(18)	(15)	(18)
Residual Change (MWh)	150	20	-140
	(73)	(66)	(79)
	Panel B: Weekday Summer Afternoons		
Predicted Change (MWh)	1068	259	822
	(47)	(17)	(39)
Residual Change (MWh)	237	76	-260
	(144)	(61)	(119)
	Panel C: High Demand Hours		
Predicted Change (MWh)	1207	174	753
	(44)	(30)	(35)
Residual Change (MWh)	431	4	-381
	(144)	(57)	(129)
Observations (Hour by Unit)	2,285,140	267,410	1,920,490
Number of Generating Units	94	11	79
Number of Plants	42	5	43
Total Capacity (MW)	15,922	2,887	11,776

Note: This table reports our estimates of the change in generation that resulted from the SONGS closure on January 31, 2012. The predicted change is the increase in generation at marginal units, assuming 2,150 MWh of lost generation from SONGS. The residual change is the difference between actual and expected generation, as explained in the text. For all calculations our sample includes hourly observations between April 20, 2010 and January 31, 2013. We exclude generating units that enter or exit during the sample period. As indicated by the column headings, we report estimates for three California regions as defined by the Path-15 and Path-26 transmission interconnections. Panel A reports estimated impacts for all hours. Panel B reports estimates for 2 p.m. to 5 p.m. in months June through September. Panel C reports estimates for hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. Standard errors (in parentheses) are clustered by sample month.

units to Southern units. Relative to our predictions, the Southern units increased generation by 150 MWh, while the Northern units decreased generation by 140 MWh. To put this in perspective, the average plant-level capacity is around 380 MW in the South and around 270 MW in the North, so these effects are approximately half the size of a typical plant. The results are starker when the sample is limited to the hours in which transmission constraints are most likely to bind. On weekday summer afternoons (Panel B), the residual effect almost doubles, to a 237 MWh increase in the South and 260 MWh decrease in the North. In the five percent of hours with the highest level of system demand (Panel C), the residual effect is an increase in the South of 431 MWh and a decrease in the North of 381 MWh. The estimates indicate that during peak periods as much as 75 percent of the lost generation from SONGS was met by plants in Southern California. This is comparable to an increase in capacity factor of three percentage points in the South and a decrease of three percentage points in the North.

These results implicitly assume that the entire displaced SONGS generation (2,150 MWh) was met by in-state CEMS units. This is a reasonable approximation given the lack of responsiveness in all other categories of generation observed in Figure 3. The one notable exception is imports, which are responsive over some ranges of demand. To account for this, we calculated the predicted impact on imports of a shock to total demand equal to 2,150 MWh, using the generation regression for imports. This exercise implies that around 25 percent of the lost generation from SONGS would have been replaced by imports. One could imagine adjusting the predicted estimates in Panel A of Table 3 accordingly. For weekday summer afternoons and high demand hours, however, we find a very small response in imports, consistent with the visual evidence in Figure 3. On weekday summer afternoons, only 4 percent of the lost generation would have made up by imports, and in high demand hours it would have been less than 1 percent. Further details, discussion, and figures plotting post-period generation regressions by category are presented in the Online Appendix.

The table also reports standard errors. The predicted changes are estimated with a high degree of statistical precision and all nine estimates are strongly statistically significant. The estimated residual changes are much less precise and only marginally statistically significant in Panel A. In the Online Appendix, we report results from a series of placebo tests aimed at determining how unusual it is to observe this magnitude and pattern of residual effects. In particular, we repeat the analysis six times using the exact same specification, but with different years. In the first placebo test, for example, we estimate the model as if SONGS had closed in January 2007 rather than January 2012. Overall, the estimated residual effects in these other years do not follow the pattern observed in 2012. Some of the estimates are similar in size to our main results. However, when one looks closely at non-zero residual effects in other years, they tend to be driven by long outages. To demonstrate this, we show several additional diagnostics on the estimated residuals. In the placebos with the largest estimated residual effects, the standard deviation, skewness, and kurtosis are all larger (in absolute terms) than in 2012, indicating extended outages and other large year-to-year changes in generation at a few individual plants rather than correlated changes in generation across many plants.

5.2 Impact on Generation Costs

We next quantify the change in the total cost of production associated with these generation impacts. As is common in the literature, we calculate marginal cost for each generating unit using information on heat rates, fuel prices, and variable operations and maintenance costs (VOM): $MC_j = heat\ rate_j \cdot fuel\ price_j + VOM_j$. Details on these calculations are provided in the Online Appendix.[21] The resulting marginal cost estimates range from \$24 per MWh for generating units with favorable heat rates to \$81 per MWh for units with high heat rates.

In Figure 5, we plot the marginal cost curve for electricity in California for 2012. To construct this figure, we used data from several sources to calculate the marginal cost of every electric-generating unit in California. We overlay on the marginal cost curve a histogram of total hourly generation in the post-period. In most hours, the marginal generating unit is a combined cycle natural gas unit, with marginal cost (given the average post-period natural gas price) of around \$27 per MWh. In high demand hours, however, the marginal unit is typically either a combustion turbine or a boiler (again, fueled by natural gas), with marginal cost around \$40 per MWh.

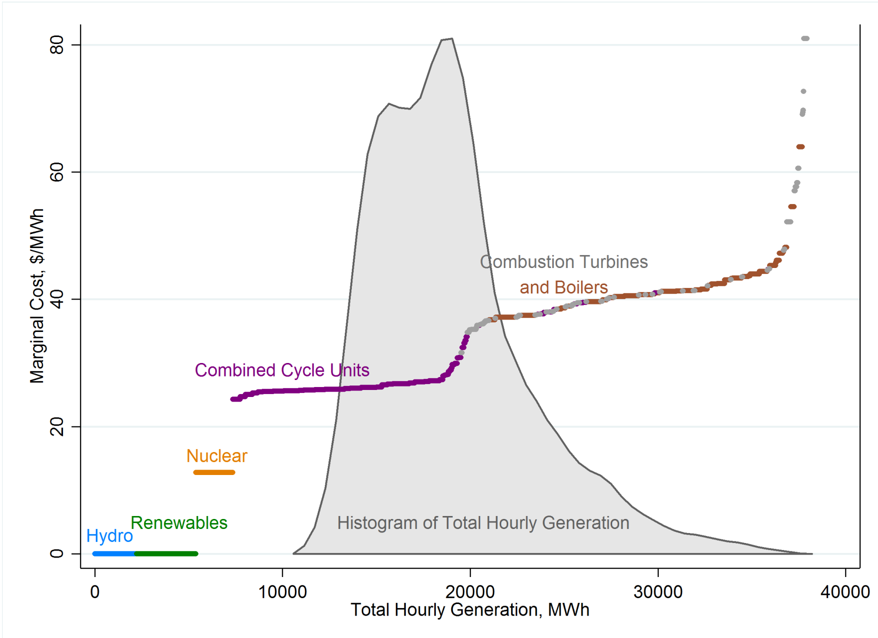
To quantify the cost impact of the SONGS closure we run regressions similar to the unit-level generation regressions, except the dependent variable is now the cost of generation rather than the quantity:

$$(MC_j \cdot generation_{jt}) = \sum_b (\delta_{bj} \cdot \mathbb{1}\{system\text{-}wide\ thermal\ generation_t = b\}) + \mu_{jt}. \qquad (5)$$

This regression again allows us to report separate estimates for predicted and residual changes. Results are given in Table 4. The predicted increase in the total hourly cost of thermal generation was \$29,000 in the South, \$8,000 in the Central region, and \$27,000 in the North – totaling \$63,000 statewide. The average cost implied is approximately \$29 per MWh. These estimates again assume that none of the lost generation from SONGS was replaced by imports. This is likely a good approximation because the California marginal cost curve is quite elastic in most hours, so the marginal cost of out-of-state generation necessarily must have been close to the marginal cost of the in-state generation. As such, we expect our estimate of \$63,000 to be close to the true change accounting for imports.

[21] This calculation abstracts from ramping rates and other dynamic considerations. This is common in the literature, but Reguant (2014) finds that start-up costs play an important role in bidding behavior and production patterns. Our preferred specification uses constant heat rates, thus averaging across differential fuel use during start-up and ramping, so as not to bias our results with changes over time in heat rates driven by confounding factors. To verify that our results are not sensitive to this specification, we considered several alternatives that allowed heat rates to vary over time. With these alternative specifications our results are qualitatively similar, and the estimate of the total cost impact of the SONGS closure is about five percent smaller.

Figure 5: The Marginal Cost of Electricity in California, 2012



Note: This figure was constructed by the authors using their measures of marginal cost and capacity for electricity generating resources in the state of California in 2012. Imports are not included. See the text for details.

The residual changes are also significant, and their spatial pattern follows what would be expected from transmission constraints. While total hourly generation costs increased by $7,100 in the South and $500 in the Central region, it decreased by $3,000 at Northern generating units because of the decrease in quantity. System-wide, this implies an average hourly increase of $4,500 coming from the residual changes in generation. While lower-cost units were available in the North, they could not be used because of the transmission constraints. This residual effect reflects not only North-South transmission constraints, but also local transmission constraints in and around San Diego and Los Angeles, as well as other physical limitations of the grid. Part of the challenge with SONGS closing was that there was now very little generation in northern San Diego county that could be used to boost the voltage of electricity transmitted from far away.[22] Maintaining some "reactive" power locally is another reason for higher-cost Southern units to operate more than predicted in 2012.

The total cost increase at thermal power plants statewide, averaged across all hours and

[22]Electricity gradually drops in voltage when it is transmitted long distances, so some local generation is necessary to complement electricity produced far away. Much of the attention since the SONGS closure has been on adding local generation, and in particular, on adding generation that provides "reactive" power for voltage regulation. In 2013, two generators at the Huntington Beach Plant were converted to synchronous condensers to provide local voltage support CAISO (2013a). Since 2013, CAISO has also been taking steps to expand local transmission capacity in and around San Diego County (CAISO 2013d; CAISO 2014).

Table 4: The Effect of the SONGS Closure on Thermal Generation Costs

	Average Hourly Change in Total Generation Cost, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Predicted Change ($000's)	28.6	7.9	26.5
	(0.6)	(0.4)	(0.5)
Residual Change ($000's)	7.1	0.5	-3.0
	(2.9)	(1.7)	(2.5)
	Panel B: Weekday Summer Afternoons		
Predicted Change ($000's)	41.6	7.5	27.4
	(1.6)	(0.5)	(1.4)
Residual Change ($000's)	8.8	1.4	-9.1
	(5.1)	(1.6)	(4.2)
	Panel C: High Demand Hours		
Predicted Change ($000's)	49.7	5.7	27.8
	(1.9)	(0.8)	(1.4)
Residual Change ($000's)	16.3	-0.5	-14.5
	(4.8)	(1.7)	(4.8)
Observations (Hour by Unit)	2,285,140	267,410	1,920,490
Number of Generating Units	94	11	79
Number of Plants	42	5	43
Total Capacity (MW)	15,922	2,887	11,776

Note: This table reports estimates of the cost of meeting the lost generation from SONGS during the first twelve months following the closure. The format of the table and underlying data are identical to Table 3, but we have used our measures of marginal cost for each generating unit to calculate the change in total generation cost. This includes changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. Standard errors (in parentheses) are clustered by sample month.

including both predicted and residual effects, is almost $68,000 per hour. This amounts to a 13 percent increase in total in-state generation costs.[23] As another point of comparison, the average post-period price in the California wholesale electricity market (quantity-weighted) was $32 per MWh. Multiplying this by total quantity (i.e. 2,150 MWh) gives $68,000 per hour. The two measures are quite close together because the supply curve is fairly elastic in most hours throughout the year. Thus the cost of the marginal generating unit is not very different from the cost of inframarginal units.

Panels B and C of Table 4 report estimates of the generation cost impacts for weekday

[23]To calculate this, we assume that the average hourly cost for other thermal generation (i.e., not observed in the CEMS data) is equal to the average cost we observe in our sample.

summer afternoons and high demand hours, when transmission constraints are more likely to bind. The predicted effects are larger than in Panel A, because the marginal generating units at these hours are higher up on the marginal cost curve. The change is particularly high in the South, where the generation impacts were larger. The residual changes in total cost are also higher than in Panel A, reflecting a combination of larger residual changes in generation and higher marginal costs. Imports do not substantially increase during peak periods, so we expect these estimates to be close to the true total change in cost. The system-wide total hourly change in thermal costs is $78,000 on weekday summer afternoons, and $84,000 in high demand hours. For comparison, the average weekday summer afternoon wholesale price (quantity-weighted) was $49 per MWh. Multiplying this by SONGS capacity gives $106,000 per hour. The same calculation for high demand hours (Panel C) also gives $106,000 per hour. These measures are considerably higher than our estimate because supply is relatively inelastic during these hours so the marginal generating unit has a much higher cost than the inframarginal units.

5.3 Impact on Emissions

In addition to the private cost of generation we calculate above, we quantify the impact of the generation changes on carbon dioxide emissions. Using the CEMS data, we first calculate carbon emissions rates for all generating units in our sample. We then use the same type of regression as we used for the generation and cost changes, but now with carbon dioxide emissions, in metric tons, as the dependent variable:

$$(carbon\_rate_j \cdot generation_{jt}) = \sum_b (\lambda_{bj} \cdot \mathbb{1}\{net\ system\text{-}wide\ demand_t = b\}) + \nu_{jt}. \qquad (6)$$

Summing across all plants and all hours, we estimate an average increase of 1,030 tons per hour during the 12 months following the SONGS closure. For comparison, the average hourly total emissions at CEMS plants was 3,730 tons between 2009 and 2011, so this is more than a 25 percent increase in total emissions. As with the previous calculations, this assumes that none of the lost generation from SONGS was replaced by imports. If the emissions rates of marginal out-of-state generators are comparable to the emissions rates of the CEMS plants we observe, then our carbon calculations will be approximately correct. If, however, there are *marginal* generators out-of-state that are fueled by coal, then our estimates will understate the total carbon impact. These calculations also assume that none of the emissions were offset via California's cap and trade program for carbon dioxide. While California power plants are currently covered by a carbon cap and trade program, they were not yet covered in 2012. As a result, the 2012 increase in carbon dioxide emissions caused by the SONGS closure would not have been offset.[24]

We also examine the impact on sulfur dioxide and nitrogen oxides emissions. Our estimates imply that the SONGS closure increased emissions of both pollutants. However, natural gas plants emit small enough amounts of these criteria pollutants that the implied economic cost of the change in emissions is small compared to the carbon dioxide impacts. See Muller and Mendelsohn (2012) for recent estimates of marginal damages. Moreover, a portion of NOx emissions are capped in the RECLAIM market around the Los Angeles area, so some of these increases may have been offset by decreases in other sectors.

5.4 Total Impact of SONGS Closure

Table 5 summarizes the total impact of the SONGS closure. We find that the SONGS closure increased thermal generation costs by almost $68,000 per hour during the first 12 months following the closure. California nuclear plants have a marginal cost of about $12.8 per MWh, so the SONGS closure also represents a savings of about $28,000 per hour. Thus the total net increase in generation costs is $350 million during the first twelve months. This includes a predicted net increase of $311 million and a residual net increase of $40 million. Finally, using a social cost of carbon of $35 per ton,[25] our estimates imply an increase in external costs of $316 million during the first 12 months.

The table also reports standard errors. As with our previous results, the predicted effect is much more precisely estimated than the residual effect. With the predicted effect, identification comes from hour-to-hour comparisons between periods with different levels of net system demand. There is rich variation in net system demand driven by weather and other factors, so the coefficient estimates are precisely estimated. Identification of the residual effects relies in addition on comparing coefficient estimates before and after the SONGS closure, and consequently these are less precisely estimated. Moreover, with the placebo tests that we described in Section 5.1, it is not unusual to observe large year-to-year residual effects. All six placebo estimates of the residual net increase in generation costs are smaller than $40 million, but in some years the estimate is close in magnitude. Overall, the placebo results suggests that while the pattern of residual effects in 2012 is indeed atypical, the $40 million estimate should be interpreted cautiously.

These estimates provide some of the components necessary for thinking about the private

[24]Our annualized cost estimate does include January 2013 emissions, which totalled 0.7 million tons. These were covered by the new cap and trade program, but at a permit price of under $15 (source: calcarbondash.org, based on ICE contracts), compared to the IWG's social cost of carbon of $35 per ton that we use later in the analysis. Accordingly, only 3 percent of the twelve-month carbon costs that we report would have been internalized.

[25]The central value of the social cost of carbon used by the U.S. federal government for regulatory impact analysis is $32 per ton (in 2007$) (IWG 2013), equivalent to $35 per ton in 2013 dollars.

Table 5: The Total Impact of the SONGS Closure

	Total Impact during the Twelve Months following the Closure (Millions of Dollars)
Predicted Net Increase in Generation Costs	311 (3.1)
Residual Net Increase in Generation Costs	40 (10.7)
Value of Increased Carbon Dioxide Emissions	316 (5.8)

Note: This table reports our estimates of the total economic and environmental impact of the SONGS closure. The predicted net increase subtracts generation costs at SONGS from the predicted increase in thermal generation costs. The residual net increase is the additional increase in generation costs due to deviations from predicted plant behavior. These generation cost impacts include changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. Carbon dioxide emissions are valued at $35/ton. All dollar amounts in year 2013 dollars. Standard errors (in parentheses) are clustered by sample month.

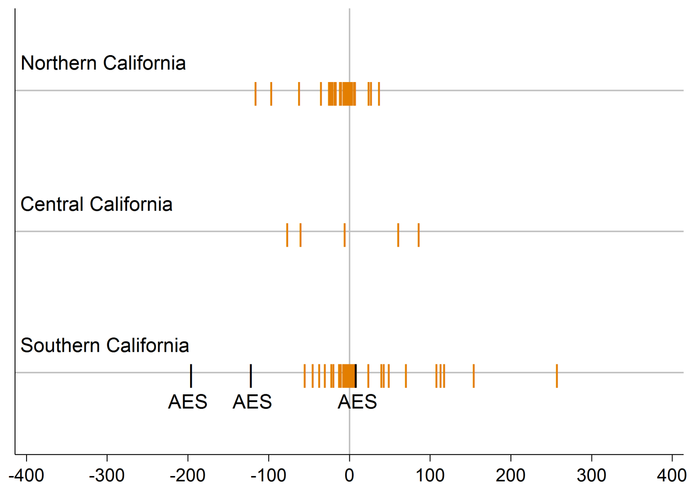
and social consequences of nuclear plant closures. In addition to generation cost impacts, the other relevant private cost is the fixed O&M required to keep a nuclear plant open. For SONGS, these costs were about $340 million per year, approximately the same magnitude as the generation cost impacts. Discussions about nuclear plant closures also typically center around the external costs associated with operating a nuclear power plant including storage of spent fuel and accident risk. Quantifying these risks is very difficult because they involve small probabilities of large damages.

These results also highlight the evolving economics of U.S. nuclear power. The generation cost impacts would have been much higher if natural gas prices had not fallen so much in recent years. At the level of natural gas prices seen in 2007, for instance, the generation cost impacts from the SONGS closure would have been more than twice as high. Along a similar vein, the convexity of the supply curve implies that the generation cost impacts also could have been much higher had the system been further stressed by an extended period of hotter-than-average weather or an outage at another major power plant.

5.5 Unusual Behavior at Individual Plants

Our empirical approach generates estimates of predicted and residual effects not only at a regional level, but also for individual plants. In the Online Appendix we show that these plant-level estimates are what one would expect based on the marginal cost curve. For example, across all hours, the largest predicted increases in generation are at large combined-cycle plants with low marginal cost. Also, the largest positive residuals tend to be at plants located

Figure 6: Plant-Level Residual Changes in High Demand Hours



Note: This figure plots plant-level hourly average residual changes by region. High demand hours are defined as hours when total CEMS generation was in the 13th quantile (13,837 MWh) or greater. Estimates for AES-owned plants are indicated with black lines, while all other estimates are orange. Details on the calculations are given in the text.

in the South while the largest negative residuals tend to be at plants in the North.

During high-demand hours the plant-level estimates have a more distinct regional pattern. The largest predicted increases are at steam boilers and other plants with high marginal cost. The largest residual increases are at Southern plants. Also, as expected, several of the largest residual decreases are at plants in the North. There are two important exceptions, however. The two largest residual decreases in high demand hours were at plants in the South: Alamitos and Redondo, both owned by AES. These two large plants were on the margin in high demand hours, and they had large predicted changes. Moreover, given their location in the South, they would have been expected to have residual *increases*. To illustrate the anomaly these plants represent, we plot in Figure 6 estimated residual effects by plant for high demand hours, separated by region. The AES plants are shown with black lines, while all other plants are shown with orange lines. While the other Southern California plants generally exhibit positive residual effects, the estimated residual effects for two of the three AES plants are clearly large and negative.

As it turns out, the AES plants have been investigated for market violations. They were operated through a tolling agreement with JP Morgan Ventures Energy Corporation, a subsidiary of JPMorgan Chase. Following investigations by the California and Midcontinent System Operators (CAISO and MISO), the Federal Energy Regulatory Commission alleged market manipulation by JP Morgan at these and other plants.[26] FERC, CAISO, and MISO asserted that JP Morgan engaged in twelve different manipulative bidding strategies between September 2010 and November 2012 in both the California and Midcontinent markets. Some of the strategies, particularly in 2011, were designed to lead the independent system operator to schedule the generating units even when it was uneconomical to do so, then to pay prices above the wholesale price through so-called make-whole payments. Other strategies, particularly in 2012, involved submitting extremely high bids but relying on the ISO's dynamic scheduling constraints to lead the bids to be accepted.[27] In 2013, JP Morgan agreed to pay a civil penalty of $285 million and to disgorge $125 million in alleged unjust profits.

6 Conclusion

Motivated by dramatic changes in the profitability of existing U.S. nuclear power plants, we examine the exit decision of a large nuclear plant in California. We find that the SONGS closure increased the private cost of electricity generation in California by $350 million during the first twelve months. For comparison, the annual fixed costs of keeping the plant open were around $340 million, corroborating anecdotal reports about nuclear power plant profitability. Of the $350 million, $40 million reflects costs not predicted by the pre-period supply curve. This reflects transmission constraints and other physical limitations of the grid that necessitated that a high fraction of lost generation be met by plants located in the Southern part of the state. These constraints also increased the scope for market power, and we find evidence consistent with one company acting non-competitively.

The closure also had a large environmental impact. Because virtually all of the lost production from SONGS was replaced by natural gas generation, the closure increased carbon dioxide emissions by 9 million metric tons during the first twelve months. At $35 per ton, the economic cost of these emissions is almost $320 million. A large fraction of nuclear plants worldwide are beginning to reach retirement age, and it is important to take these external costs into account as decisions are made about whether or not to extend the operating lives of these plants. Current policies aimed at reducing carbon emissions tend to focus on wind, solar,

[26]To understand FERC's charges against JP Morgan it is helpful to have a bit of broader legal context. Regulatory oversight of electricity is different than for many goods, in that it is illegal to exercise unilateral market power. FERC is charged with a statutory mandate dating back to 1935 which requires wholesale electricity prices to be "just and reasonable," allowing for the recovery of production costs and a "fair" rate of return. See Wolak (2005) for additional discussion.

[27]For details on the individual strategies, see FERC (2013). Since FERC alleged market manipulation in both the pre- and post-periods, we do not know whether the residual decreases at Alamitos and Redondo are a result of unusually high generation in 2011 or withholding in 2012. Also, while much of the manipulation alleged by FERC was aimed at earning revenues through exceptional dispatch and other out-of-market operations, we do not observe these payments.

and other renewables, but keeping existing nuclear plants open longer could mean hundreds of millions of tons of carbon abatement.

Our results also illustrate the challenges of designing deregulated electricity markets. Wolak (2014*b*) argues that while competition may improve efficiency relative to regulated monopoly, it also introduces cost in the form of greater complexity and need for monitoring. Transmission constraints add an additional layer to this complexity by implicitly shrinking the size of the market. Constraints increase the scope for non-competitive behavior, but only for certain plants during certain high-demand periods. Understanding and mitigating market power in these contexts is difficult and requires an unusually sophisticated regulator.

Despite these challenges, the experience in California in 2012 also provides some cause for optimism. An enormous generating facility closed suddenly and unexpectedly during a year with low hydroelectric generation, yet there was essentially no disruption in supply and wholesale prices remained steady. In part, these 'steady' prices were only an illusion, driven by a lucky coincidence in the form of decreased natural gas prices. However the experience also points to a more mature, more flexible market that, although imperfect, provides many of the right incentives for generation and investment.

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For Online Publication

Appendix

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- 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

[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.

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 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

[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.

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.

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

[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.

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, 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

[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.

[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.

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 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 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),

[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).

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.

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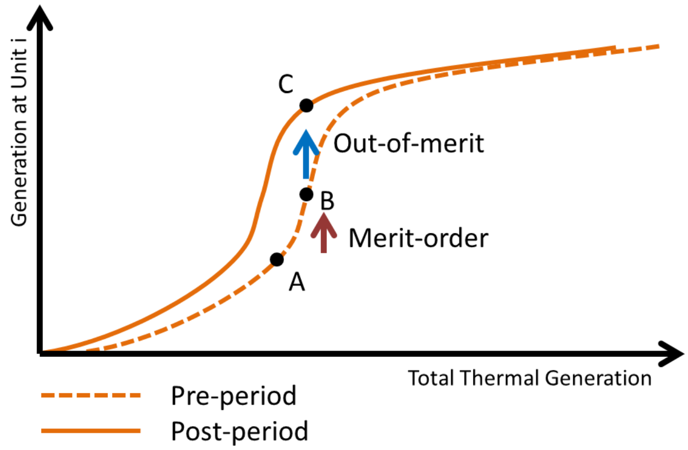
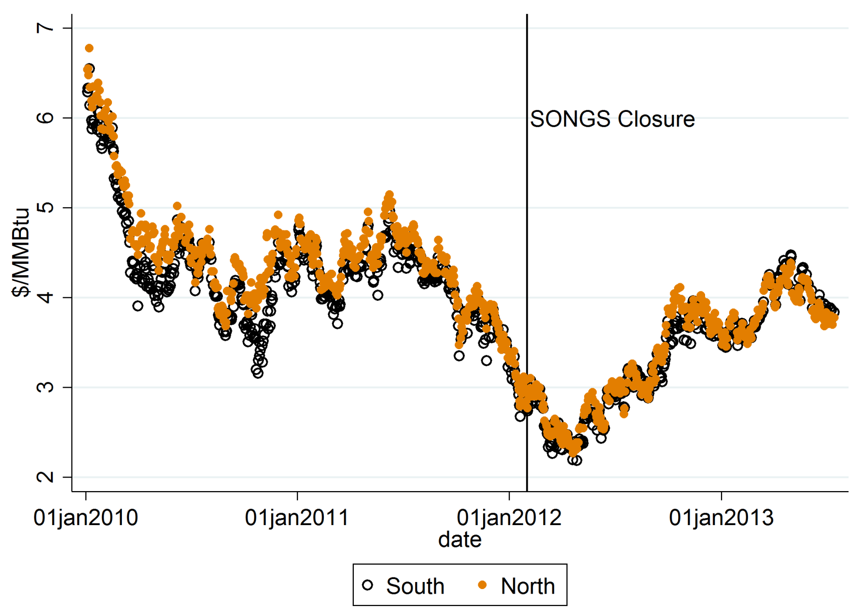
Appendix Figure A1: Predicted and Residual Effects

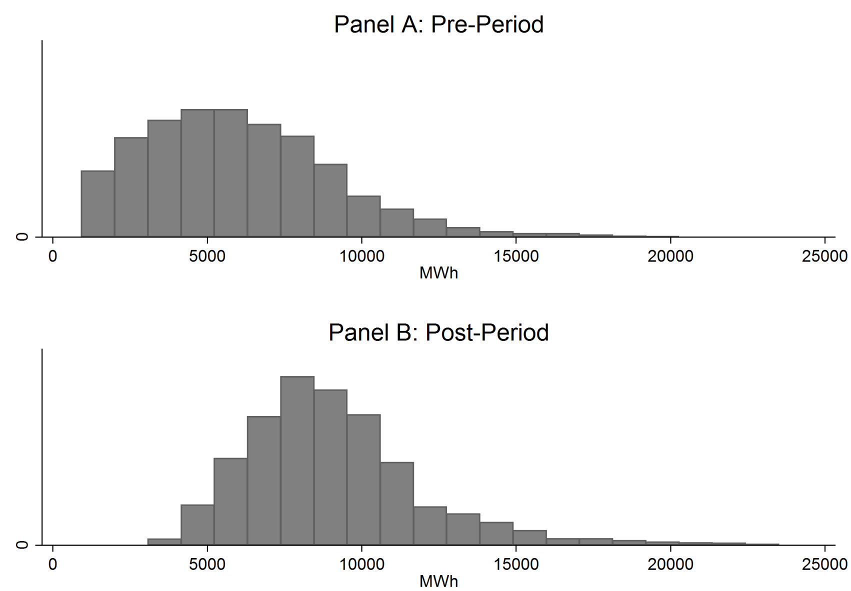


Appendix Figure A2: Natural Gas Prices, by Region



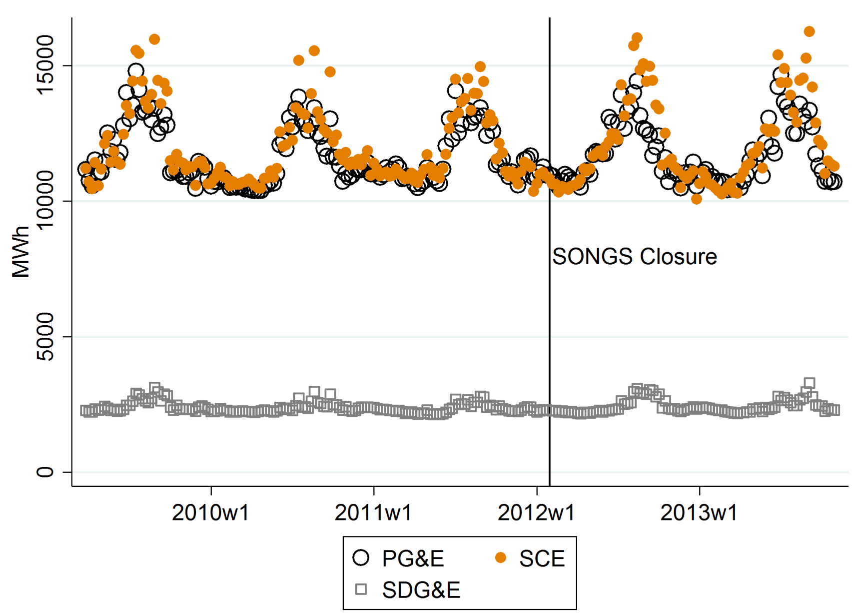
Note: This figure plots daily natural gas prices, in $/MMBtu, for Northern California (PG&E citygate) versus Southern California (SCG citygate). Data are from Platts Gas Daily.

Appendix Figure A3: Histogram of Hourly Total CEMS Generation



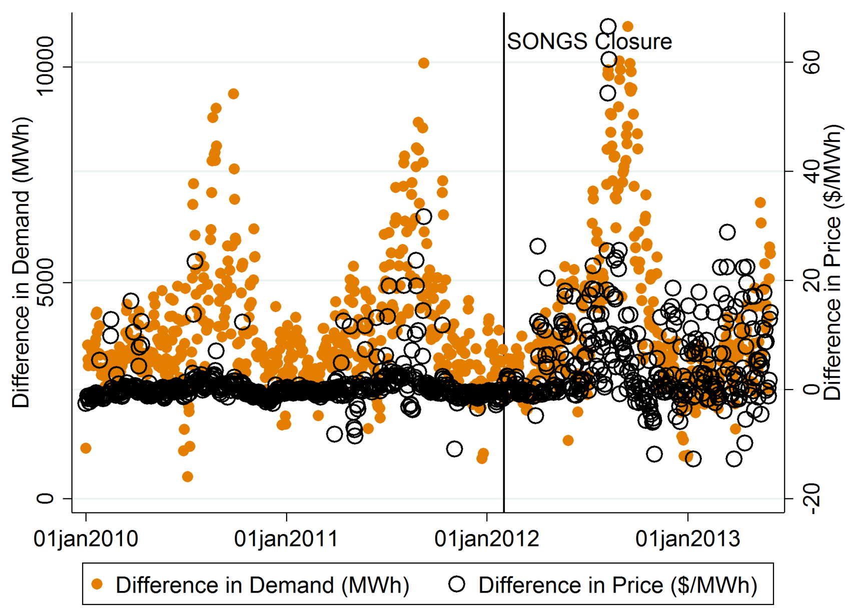
Note: This figure shows histograms of total hourly generation from CEMS units in the year leading up to the SONGS closure (Panel A) and in the year following the closure (Panel B). The shift to the right in Panel B reflects both the closure of SONGS and concurrent changes in non-thermal generation (especially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

Appendix Figure A4: Regional Demand



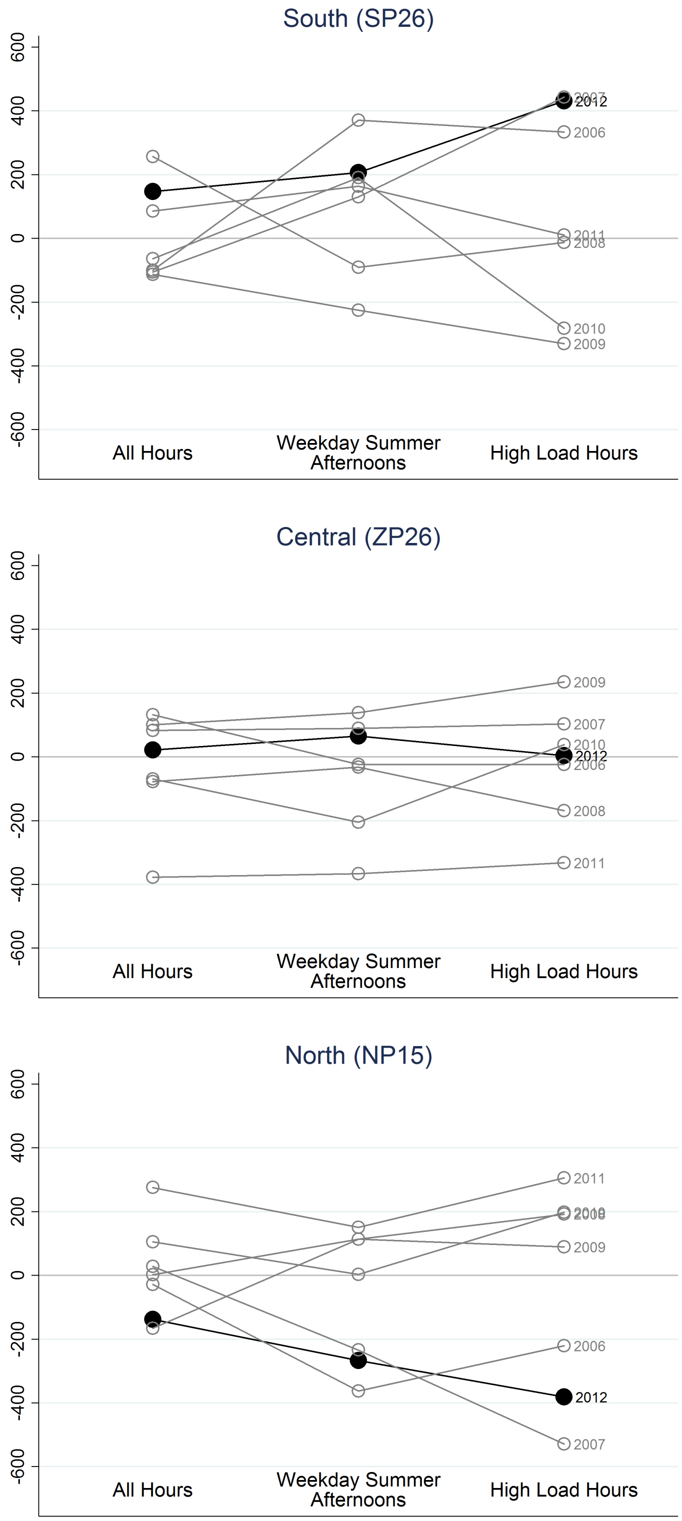
Note: This figure plots average hourly quantity demanded by week for the three California investor-owned utilities. The vertical line shows the week the second SONGS unit went down. PG&E is roughly the Northern half of the state, SCE is the Southern half excluding the San Diego area, and SDG&E is the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

Appendix Figure A5: Regional Demand and Price Differentials



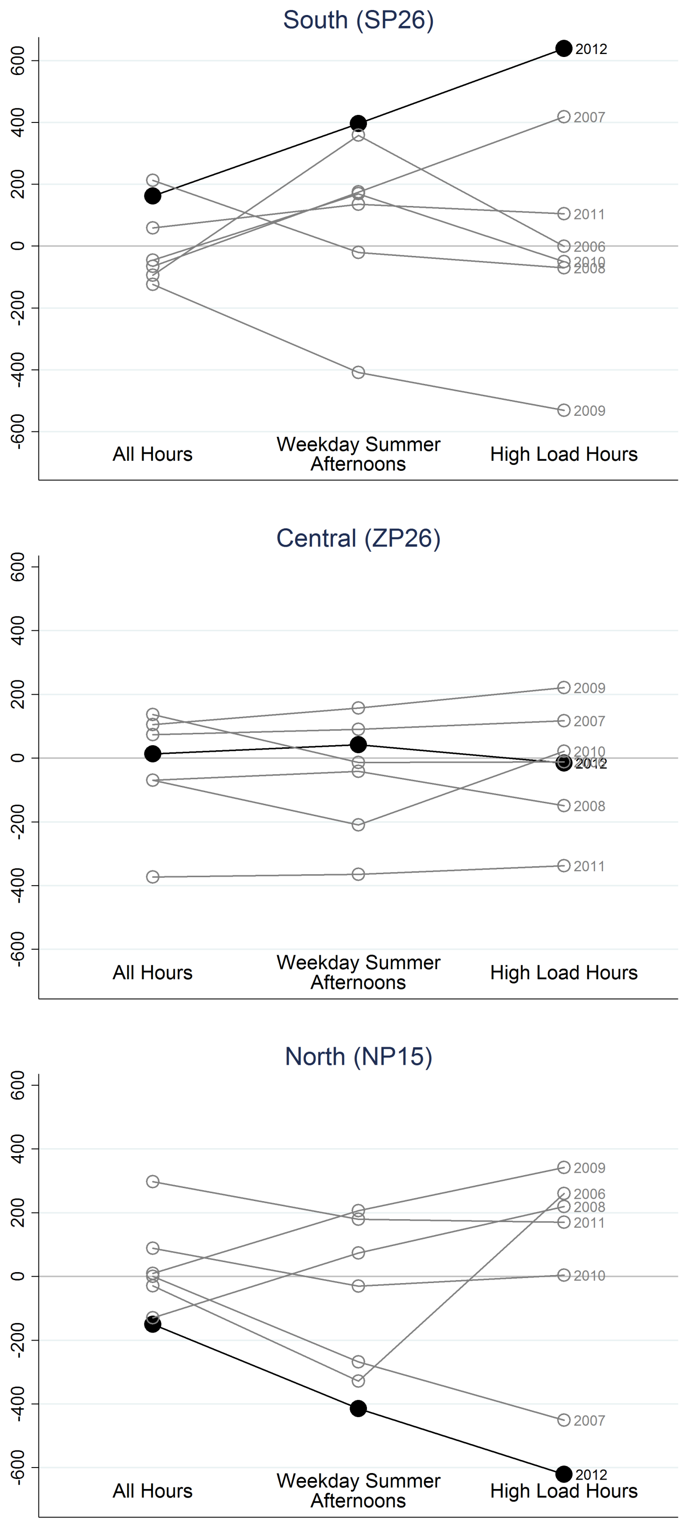
Note: This figure plots quantity demanded and price differentials at 3 pm daily between January 2009 and September 2013. Weekends are excluded. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Appendix Figure A6: Residual Changes, by Year



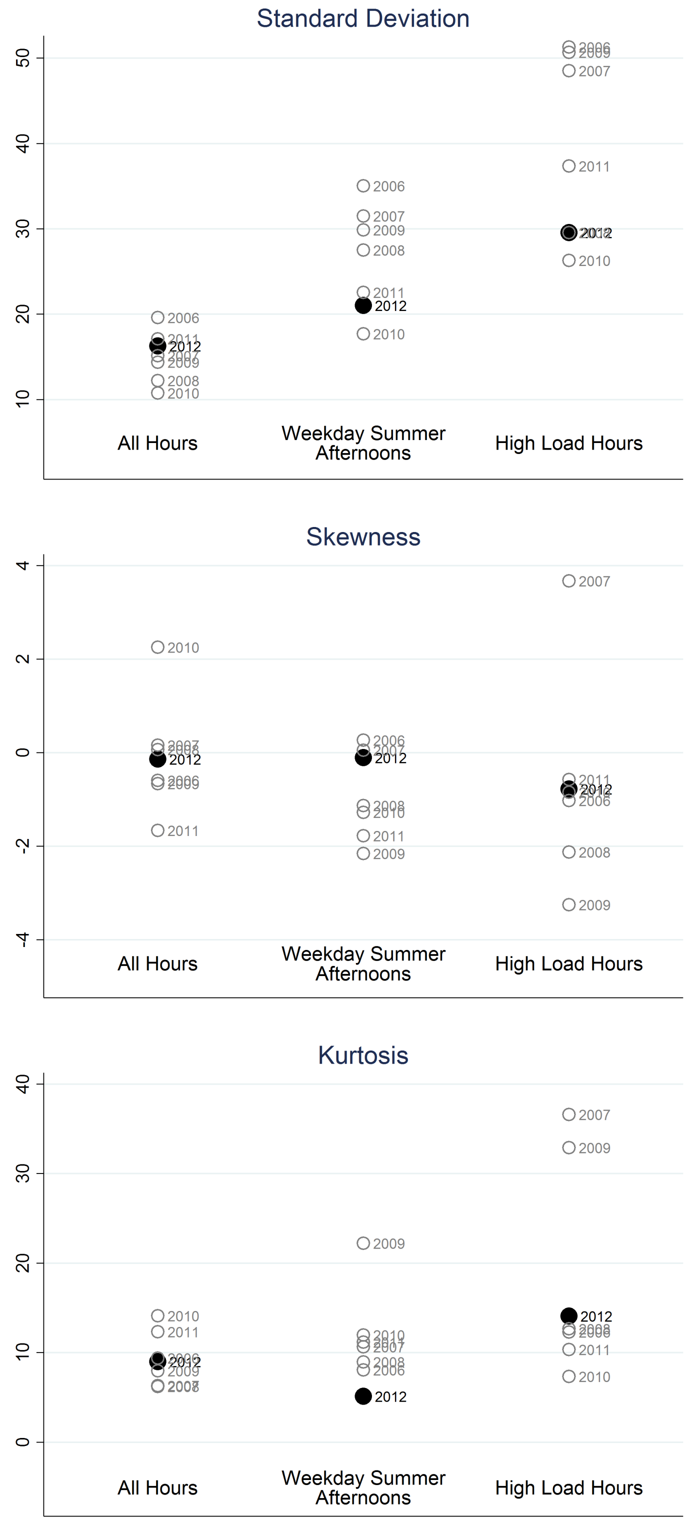
Note: These figures show residual estimates for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

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



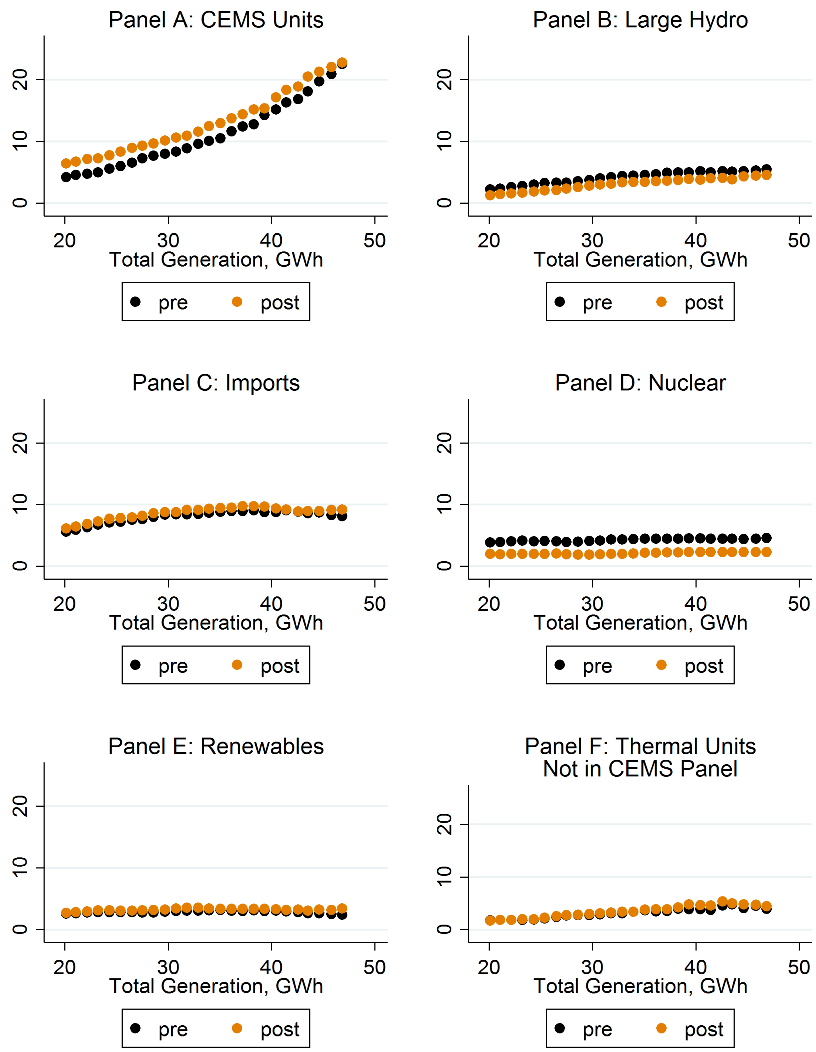
Note: These figures show residual effects based on estimates from a sample that excludes AES plants for the main period of interest (2012, in black) compared to other years for which we have data (hollow grey circles).

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.

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.