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Abstract

The San Onofre Nuclear Generating Station (SONGS) was closed abruptly and permanently in February 2012. During the previous decade, SONGS had produced about 8% of the electricity generated in California, so its closure had a pronounced impact on the wholesale market, requiring large and immediate increases in generation from other sources. In this paper we use publicly available micro-data from a variety of sources to examine the impact of the closure on market outcomes. We find that in the months following the closure, almost all of the lost generation from SONGS was met by natural gas plants inside California at an average cost of $66,000 per hour. During high load hours, we find that as much as 75% of the lost generation was met by plants located in the southern part of the state. Although lower-cost production was available elsewhere, transmission constraints and other physical limitations of the grid severely limited the ability of other producers to sell into the southern California market. The transmission constraints also made it potentially more profitable for certain plants to exercise market power, and we find evidence that one company, in particular, may have acted non-competitively.

Key Words: Electricity Markets, Transmission Constraints, Nuclear Outages, Carbon Emissions

JEL: L51, L94, Q41, Q54

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1 Introduction

Between 2005 and 2011, the San Onofre Nuclear Generating Station (SONGS) generated an average of 16 million megawatt hours of electricity annually, making it one of the largest electric generating facilities in California. During this period, SONGS generated enough power to meet the needs of 2.3 million California households[1] – about 8% of all electricity generated in the state. Moreover, SONGS was 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, implying that a large part of demand must be met locally.

SONGS was closed abruptly in February 2012, when workers discovered problems with the plant's recently replaced steam generators. Initially, the outage was expected to be temporary, but additional problems were discovered, and the facility was closed permanently. Because of the plant's size and prominence, the closure provides a valuable natural experiment for learning about firm behavior in electricity markets. Nationwide, over $350 billion is spent on electricity annually, so understanding these markets is of large intrinsic interest.[2]

In this paper, we use publicly available micro-data from a variety of sources to examine the impact of the SONGS closure on market outcomes. Even in a world without transmission constraints or market power, closing a large generation source will impact the price of wholesale electricity. Like other nuclear power plants, SONGS produced power at very low marginal cost. Consequently, the plant was always near the top of the "merit-order," operating around the clock and providing a consistent source of baseload power. When SONGS was closed, this generation had to be made up for by operating other, more expensive generating resources. Thus a first pass at understanding the impact of the closure involves identifying those marginal resources that would be expected to increase production.

In addition to these merit-order effects, the closure caused transmission constraints to bind, essentially segmenting the California market. For most of the 2000s, transmission capacity between Northern and Southern California was sufficient that wholesale prices equalized in the two regions during the vast majority of hours. Although SONGS was occasionally shut down temporarily for refueling or maintenance, plant managers were careful to schedule these outages during the winter, when demand is low. Beginning with the permanent closure in

[1]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.

[2]Ibid. Tables T2 and T4.

2012, we document a substantial divergence in prices between the North and the South.

This binding transmission constraint meant that it was not possible to meet all of the lost output from SONGS using the lowest cost available generating resources. We find that during low load hours, the change in generation follows closely the merit order, with about half of the increased generation coming from Southern California and the other half coming from Northern California. During high load hours, however, we find significant "out-of-order" effects: higher cost generating units coming online more than we would have expected. In high load hours in 2012, for instance, we find that as much as 75% of the lost generation was met by plants located in Southern California.

Distinguishing between merit-order and out-of-order effects is challenging because one must construct a credible counterfactual for what the pattern of generation would have been without transmission constraints. The empirical strategy that we adopt in the paper is to exploit the fact that prior to the closure, transmission constraints were rarely binding in the California market. We use data from this pre-period to describe flexibly the relationship between unit-level generation and system load. We use these estimates to predict what operating behavior would have been after the SONGS closure were there no transmission constraints. We then compare generating units' actual behavior with this counterfactual to measure out-of-order effects. This approach affords several advantages over a naive before and after comparison. We are able to account for concurrent changes to hydroelectric resources, renewable resources, demand, and fuel prices – all of which would confound a before and after comparison. Additionally, a simple before and after comparison would conflate the merit-order and out-of-order effects.

Our results provide a detailed account of economic and environmental outcomes. We find that the SONGS closure increased the cost of electricity generation in California by about $369 million during the first twelve months. This is a large change, equivalent to a 15 percent increase in total generation costs, yet it went almost completely unnoticed because of a large offsetting decrease in natural gas prices that occurred in 2012. In fact, a naive before-and-after calculation would have found erroneously concluded that the SONGS closure actually *decreased* electricity prices. The SONGS closure also had important implications for the environment, increasing CO_2 emissions by 9.2 million tons in the twelve months following the closure. To put this in some perspective, this is the equivalent of putting more than 2 million additional cars on the road, and implies a social cost of emissions of $331 million per year.[3]

[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

Of this \$369 million in increased private generation costs, we attribute \$39 million to transmission constraints. This number is less precisely estimated than the overall impact, but it is particularly interesting in that it provides a measure of the value of transmission. The California Independent System Operator evidently agrees that the constraints are costly, and since 2013 has been taking steps to increase transmission capacity.

We are also able to determine which individual plants were most affected by the SONGS closure. Because of the transmission constraints, the largest out-of-order increases are at Southern plants, and the largest out-of-order decreases are at Northern plants. We also find large out-of-order decreases during high load hours at two Southern plants: Alamitos and Redondo, both owned by the same company. This is surprising but, as it turns out, not coincidental. The Federal Energy Regulatory Commission alleged market manipulation at these plants over the period 2010 to 2012, for which JP Morgan paid fines of over \$400 million. This suggests that our approach may serve as a useful diagnostic tool. Although a large out-of-order effect does not prove that a plant is exercising market power, it is a good indicator of unusual behavior.

Our paper contributes to a small but growing literature on the value of the geographic integration of electricity markets (Mansur and White, 2012; Ryan, 2013; Birge et al., 2013). Previous studies of transmission constraints in electricity markets have either used stylized theoretical models (Cardell, Hitt and Hogan, 1997; Joskow and Tirole, 2000) or Cournot simulations (Borenstein, Bushnell and Stoft, 2000; Ryan, 2013). Our methodology is novel, as it decomposes changes in quantity into merit-order and out-of-order effects without requiring strong assumptions about the firms' objective function or an explicit representation of the physical constraints of the electric grid. In essence, the SONGS closure allows us to observe the market both with and without transmission constraints.

We see broad potential for applying this approach in other electricity markets. Whereas most economic studies of wholesale electricity markets have relied on confidential data from the system operator and other sources, a nice feature of our analysis is that it relies completely on publicly-available data. Consequently, it would be relatively straightforward to perform similar analyses elsewhere, both for quantifying the impacts of large changes in generation and transmission infrastructure, and for diagnosing unusual changes in firm behavior.

Our paper also has important policy implications for California and beyond. Electricity transmission can have tremendous benefits through the integration of markets and the reduction of market power opportunities. At the same time, transmission is also extremely

gallons of gasoline annually. For each gallon of gasoline, 19.6 pounds of CO_2 are emitted.

expensive, so careful calculations of these costs and benefits are important. This is more true now than ever, given the large increases in capacity from wind and other forms of renewables and the anticipated retirement of large numbers of nuclear and coal plants.

2 Background

2.1 Electricity Markets

Electricity markets have several important features that make them unlike most other markets. First, electricity cannot be cost-effectively stored, so supply must meet demand at all times. Otherwise, the frequency in the grid will fall outside of a narrow tolerance band, and there will be a power outage. Second, electricity demand is highly inelastic. As a result, electricity markets clear mostly on the supply side, with generation ramping up and down to meet system load. These two features have important implications for the pattern of electricity generation, prices, and the scope for market power.

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%).[4] This mix of technologies reflects cost, flexibility, and environmental objectives. Wind, solar, and other renewables have near zero marginal cost, so they occupy the top of the merit order. Next in the order is nuclear, which has a low marginal cost relative to fossil fuel plants. Fossil fuel plants follow, with coal tending to be cheaper than natural gas. Depending on fuel prices, however, there may be some highly-efficient natural gas plants with lower marginal cost than particularly inefficient coal plants.

Regulation of electricity markets varies across states and has changed over time. Under the classic regulatory model still used in many states today, electric utilities receive exclusive rights to provide electricity within given geographic areas and are allowed to charge rates set by cost-of-service regulation. These vertically-integrated utilities typically perform all the activities required to supply electricity: generating electricity, operating the transmission and distribution networks, and providing retail services.

In part as a response to the limitations of cost-of-service regulation, several states began to deregulate their electricity markets beginning in the late 1990s. In most states, the deregulation process separated generation from transmission and distribution. Whereas most economists believe generation is potentially competitive, transmission and distribution are

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

natural monopolies. Wholesale electricity markets were established in several different regions, and regulators required utilities to sell all or part of their existing electric generating portfolios to independent power producers.

Deregulation has resulted in gains in operating efficiency (Fabrizio, Rose and Wolfram, 2007; Davis and Wolfram, 2012), but it has also introduced opportunities for generation companies to exercise market power (Borenstein and Bushnell, 1999; Borenstein, Bushnell and Wolak, 2002; Bushnell, Mansur and Saravia, 2008; Hortacsu and Puller, 2008). As with any market, the scope for individual firms to affect prices depends on the size of the market and the number of firms. With electricity, however, the lack of cost-effective storage and inelastic short-run demand makes the market particularly susceptible to market power, even when market concentration is relatively low.

Economists have also long recognized the key role of transmission capacity in deregulated electricity markets (Cardell, Hitt and Hogan, 1997; Bushnell, 1999; Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2000; Ryan, 2013). When transmission lines are unconstrained, electricity moves between markets at virtually no cost, prices are equated across markets, and the effective size of the market is large. However, when transmission capacity is limited, the effective size of the local market shrinks, potentially making it more profitable for producers to withold generation. There is also a related work on how organized markets can *increase* the effective size of the market. Mansur and White (2012) document how the expansion of a wholesale electricity market from the Eastern United States to the Midwest led to a substantial increase in efficiency, equating prices across regions and improving allocative efficiency. In this case no change in transmission capacity was necessary, only a centralized market design.

2.2 The California Landscape

California was part of this initial wave of electricity deregulation. California's wholesale electricity market was launched in April 1998, with all three major investor owned utilities required to buy and sell essentially all of their power through this new market. At the same time, the utilities were required to sell off nearly all of their natural gas power plants to independent power producers. By the end of the 1990s, independent power producers controlled more than 30 percent of the electricity generating capacity in the state.

For the first two years wholesale prices varied widely across hours, but average prices stayed below $50 per megawatt hour. Then in 2000 the nascent market was put to the test. The year was unusually dry, leading to below average hydro generation, and the summer was unusually hot, increasing demand. Starting in June 2000, wholesale prices spiked and for the next several months average monthly prices exceeded $100 per megawatt hour. This was more than twice the level observed in any previous month. The prices were devastating to the utilities, who were required to buy wholesale power on the exchange but sell it to customers at regulated rates. California's largest utility, Pacific Gas and Electric, declared bankruptcy in 2001. The state eventually intervened and suspended the market.

Most economic analyses of this period have concluded that generation companies exercised market power that pushed prices considerably higher than they would have gone due to market fundamentals (Borenstein, Bushnell and Wolak, 2002; Joskow and Kahn, 2002; Puller, 2007). Borenstein, Bushnell and Wolak (2002), for example, finds that about half of the increase in electricity expenditures during summer 2000 was due to market power. These studies are innovative in the broader industrial organization literature because they illustrate how under tight market conditions firms can exercise unilateral market power even with a small market share. This was noted in the many studies of the crisis, and also presaged by Borenstein and Bushnell (1999) using a Cournot model to simulate the California market.

The California market today looks considerably different. First, a much higher fraction of power is sold using long-term contracts. This reduces the incentive for producers to withhold generation in the spot market because they cannot influence the price of the output already committed through contracts (Allaz and Vila, 1993). Second, short-run demand for electricity in California is probably more elastic than it was in 2000. Although the vast majority of residential and commercial customers continue to face time-invariant retail prices, a growing number of California industrial customers face more dynamic rates. Third, the state's renewable portfolio standard and other state and federal policies have led to substantial investments in wind, solar, and other renewables. This has increased total generation capacity during a period in which demand has been relatively flat.

Table 1 describes electricity generation in California by source in 2011. By far the largest source of generation is natural gas, with only 1% of generation in California coming from coal. The second largest source is hydro, accounting for 21% of generation. The two nuclear plants, San Onofre and Diablo Canyon, each contributed approximately 9% of total generation in 2011. Finally, geothermal, wind, solar, and other renewables account for about 13% of total generation. Thus, overall the the California generation portfolio is substantially less carbon intensive than the rest of the United States, with more emphasis on natural gas, hydro, and renewables.

2.3 The San Onofre Nuclear Generating Station

San Onofre Nuclear Generation Station (SONGS) was a two-reactor, 2150 megawatt nuclear power plant operated by Southern California Edison (SCE).[5] SONGS was valuable to the California market not just because it generated a large amount of generation, but also because of its prime location. Located in the Northwest corner of San Diego County, SONGS provided power right in the highly-populated corridor between Los Angeles and San Diego, where there are few other large power plants.

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; the other reactor that had already been shut down three weeks prior for a routine refueling outage. 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 (NERC 2012; CAISO 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).[6]

The SONGS closure was abrupt, permanent, and unexpected, making it a valuable "natural experiment" for learning about behavior in electricity markets. It is worth noting that there is some precedent for studying changes in market behavior during changes in nuclear plant operations. In particular, Wolfram (1999) instruments for wholesale electricity prices using available nuclear capacity, exploiting the large quasi-random changes in electricity supply

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

[6] SONGS is one of three U.S. nuclear power plants to close over the last decade. Crystal River and Kewaunee were both officially closed in 2013. For a recent survey of some of the broader challenges faced by nuclear power see Davis (2012).

due to unplanned outages. Our study is different in that we focus on a *permanent* shock rather than temporary outages, but the identifying variation is similar.

The SONGS closure is particularly interesting for an empirical analysis for several reasons. Whereas most large plant closures are anticipated months or even years in advance, the SONGS closure was abrupt and unexpected. This sharpens the impact and interpretation considerably as it provided little opportunity for anticipatory investments in generation and transmission. In addition, SONGS is of interest because it is part of a deregulated electricity market. In states where generation companies are regulated using cost-of-service regulation there is less scope (and less incentive) for generating units to exercise market power in response to changes in market conditions.

Finally, the SONGS closure is particularly interesting because it evokes parallels with the California electricity crisis. The year 2012 was similar to 2000 in that both years were unusually dry, resulting in low levels of hydro generation. Removing an enormous generation source like SONGS, particularly during a bad year for hydroelectric generation, might have been expected to create tight-supply conditions much like 2000. As it turns out, however, market prices and other outcomes in 2012 were very different from the experince in 2000. We think that comparing the behavior of the market in 2012 to 2000 can yield interesting insights, both about firm behavior and market design.

3 Data

For this analysis we compiled data from a variety of difference sources including the U.S. Department of Energy, the California Independent System Operator (CAISO), and the U.S. Environmental Protection Agency (EPA). As we mentioned in the introduction, a strength of our analysis is that it relies entirely on publicly-available data.

3.1 Data from the U.S. DOE

We first assembled a dataset of annual plant-level electricity generation from the U.S. Department of Energy's *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. 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. We perform all analyses of the EIA-923 data at the annual level, relying on the other datasets listed below for within-year comparisons.[7] These data also contain some information on plant characteristics, such as operator name, technology (prime mover), and fuel type. We supplement the facility characteristics with additional characteristics (county, capacity, and vintage) from another Department of Energy dataset, the "Annual Electric Generator" data found in form EIA-860.

Table 2 describes California electricity generation in 2011 and 2012. SONGS was closed in early February 2012, so the columns 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. Interestingly, 2012 was also an unusually bad year for hydroelectric power, with a decrease of 1.3 million megawatt hours monthly. Offsetting these decreases, natural gas generation increased by 2.7 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 (IPP), and whether or not the plants are cogeneration facilities. The two largest categories are "IPP 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.).

3.2 Generation Data from CAISO

To complement the EIA generation data, we next assembled a database using publicly-available records from CAISO. About 80 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 munipally-owned Los Angeles Department of Water and Power (LADWP), which maintains its own power generation and imports power from other states through long-term contracts.

The data from CAISO describe hourly data on electricity generation by broad categories

[7] Although some monthly data is available, most California plants complete the survey only once per year.

(thermal, imports, renewables, large hydroelectric, and nuclear).[8] 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: thermal generation increases substantially while nuclear and hydro decrease.

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 offsets only about 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. 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. We examine the role of imports in greater depth in Section 4.5.

3.3 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). The CEMS data contain these hourly data as well as descriptive information for each generating unit, including owner name, operator name, location (county, latitude and longitude), technology, primary and secondary fuel, and vintage.

CEMS data have been widely used in economic studies of generator behavior because they provide a high-frequency, generating unit-level measure of generation. See, e.g., Joskow and Kahn (2002); Puller (2007); Mansur (2007); Holland and Mansur (2008). 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.[9] These plants represent 30% of total generation in California in 2011, and 62% of total natural gas generation. This 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, as discussed above, one third of natural-gas fired generation in California is from

[8] Additionally, the renewables category is broken into six subcategories (geothermal, biomass, biogas, small hydro, wind, and solar), which we use when analyzing changes to wind and solar capacity.

[9] CEMS reporting requirements do not change during our sample period. The data include a number of plant openings and closings. We have double-checked these changes and they indeed correspond to plant openings and closings, not changes in reporting status.

cogeneration, industrial, and commercial facilities, which are generally not in the CEMS data. Indeed, generation reported in CEMS in 2011 was 96% of non-cogeneration IOU and IPP natural gas-fired generation reported in the EIA data.

Despite the imperfect coverage, the CEMS data provide an important complement to the other data sources, as they are 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. Table A1 in the Online Appendix lists the largest plants (by net generation) that do not appear in CEMS. Panel A lists the five largest natural gas plants, excluding industrial, commercial, and cogeneration facilities. These plants are relatively small – the largest produced 0.5 million MWh in 2011, compared to 18 million MWh from San Onofre. Panel B lists the largest cogeneration and industrial facilities that do not appear in CEMS. These are larger than the plants in Panel A, but in generation categories that are generally less able to respond to changes in market conditions. Indeed, the EIA data described in Table 2, Panel B suggest that there was essentially no year-to-year change for these facilities between 2011 and 2012. Finally, Panel C lists the largest non-fossil fuel plants not in CEMS. These include the two nuclear plants, as well as geothermal and hydro facilities. Thus overall, the non-CEMS plants tend to be either quite small, or facility types that in general are not able to respond rapidly to market changes.

While CEMS units report their 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% of gross generation. This 4.3-percent difference is the median difference in our sample between net generation from EIA and gross generation from CEMS, after dropping some outliers.[10] Kotchen and Mansur (2013) make a similar comparison using national data, finding a 5-percent mean difference.

[10]Specifically, 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.

3.4 Price Data from CAISO

We also obtained hourly wholesale electricity prices from CAISO. We use prices at three locations: NP15 (the North), ZP26 (roughly, the LA area), and SP26 (the South). The prices are locational marginal prices from the day-ahead market, and the total price is broken down into three components: congestion, loss, and energy. Units are in dollars per megawatt hour. "Congestion" in this context refers to times when the flow of power on a transmission line is equal to the line's capacity, according to engineering standards.[11] These standards can reflect the physical limit of equipment, or can be limits imposed by the operator to protect reliability. During periods in which transmission lines are close to the constraint, CAISO uses congestion prices to clear the market, implicitly allowing for some flexibility between the value of additional flow and potential risks to reliability. The rules used for determining these prices and to clear the market are complicated and frequently updated, making them extremely difficult to model explicitly.

Figure 1 shows the weekly maximum price for the North and South. We focus in this figure on the maximum price because transmission impacts are expected to be non-linear: while North and South prices in the post-period were frequently the same, a difference in maximum prices reflects hours with binding transmission constraints. Maximum prices are generally very close prior to the SONGS closure, but they diverge substantially in 2012. Figure 2 shows the price difference between the Northern and Southern nodes at 3 p.m. each weekday, a time when transmission constraints are more likely to bind, and there is a clear increase in the post-period. There are many more days with positive differentials, including a small number of days with differentials that exceed $40.

3.5 Other Data

We supplement the generation, prices, and emissions data described above with data from several other sources:

1. The daily status of each of the SONGS reactors is obtained from the NRC Power Reactor Status reports. These reports list the daily capacity factor for each nuclear

[11] It is worth noting that this use of the term "congestion" is different from how it is typically used in economics. For example, many studies examine public goods with congestion (e.g. networks, roads, airports). With these goods the benefit per user falls as the number of users increases. Cars keep moving, for example, but more slowly. This is quite different from electricity transmission, for which there is essentially no change in benefits per user whatsoever up until the point that the constraint binds and no additional flow is feasible. This distinction is important enough that we have chosen to adopt the language "transmission constraint" throughout and avoid the term "congestion."

generating unit.

2. The OASIS data system also gives us hourly regional load. The three regions available correspond roughly to the PGE, SCE, and SDGE service territories (the former in the North, and the latter two in the South).

3. We obtain daily natural gas prices, in \$/mmbtu, from Platts Gas Daily. We focus on the PG&E City Gate price for the North, and the SCG City Gate price for the South.

4. We obtain annual average NOx prices (\$/ton) from RECLAIM annual reports for 2006-present. Higher frequency prices are not publicly available. We use prices of credits traded in the same year as the compliance year.

5. Finally, we match each generating unit to one of the three price locations using the "Control Area Generating Capability List" available from CAISO.

4 Empirical Strategy and Results

4.1 Creating a Credible Counterfactual

Our objective is to determine which power plants increased generation to make up for the 2,150 megawatts of capacity that went down starting February 2012 when SONGS closed. Although at first glance this might appear to be a relatively straightforward exercise, simple before-and-after comparisons would not be credible. As we showed earlier, hydroelectric generation was extremely low in 2012. This alone necessitated substantial increases in generation from thermal plants, making it difficult to interpret before-and-after comparisons like our Table 2.

One potential approach for estimating the *causal* impact of the SONGS closure would have been to use a regression-discontinuity (RD) research design, comparing generation immediately before and after the SONGS closure. This approach has a great deal of intuitive appeal, but is only useful for estimating a very short-run effect i.e. how did generation change in the days or weeks following the closure. Although this is somewhat interesting, we are much more interested in longer-run changes in generation patterns. In particular, we want to be able to examine June, July and August 2012, when air-conditioning and other factors lead electricity consumption to reach its annual peak. The RD approach is not helpful for examining this peak period because it occurs several months after the closure.

Instead, the approach we adopt in this paper is to construct a generating unit-level econometric model of the relationship between system load and generation, and then to use this model to quantify changes in generation post closure. The basic idea is simple. System load varies substantially hour to hour. Low-cost generating units operate most hours of the year, regardless of system load, while higher-cost generating units turn on only during relatively high load hours. The first thing we do is describe this relationship non-parametrically by estimating a series of what we call "unit-level generation regressions."

We estimate these regressions using data from before 2012, when transmission constraints were rarely binding in the California market. These regressions are thus an empirical representation of operating behavior in an unconstrained market, and they primarily reflect differences in marginal cost across generating units. During the post-period, however, we expect transmission constraints and voltage regulation concerns to change the ordering of generating units. In particular, electricity generated by units in the immediate vicinity of SONGS became more valuable, potentially leading these units to be used even at lower levels of system load.

As we describe in the introduction, we distinguish between two different effects: (1) the "merit-order" change in generation is when the next generating unit along the marginal cost curve is brought online; and (2) the "out-of-order" change in generation is when higher cost generating units that would normally be offline are brought online because of transmission constraints, voltage support, or other considerations. In this section we describe our approach in detail, highlighting the key assumptions required for each stage in the analysis.

Note that we use a reduced form approach, rather than either an engineering model of the electrical grid or a structural model of firm behavior. Either of these alternative approaches would have required us to explicitly model the transmission constraints and other physical limitations of the grid. Although engineering models exist with this level of detail (e.g. GE MAPS), they rely on strong simplifying assumptions that only approximately describe Kirchhof's laws and the engineering properties that govern how electricity moves. In practice, in operating the electric grid system operators rely on a combination of output from models and real-time information about system conditions. Our reduced form approach is a valuable complement, relying heavily on observed market behavior to make inference about system constraints.

Our method also differs from a structural model of firm behavior, in that we do not attempt to fully solve the firms' profit maximization problem. Although the objective function is relatively clear, particularly for merchant generators, the constraints are not. To formally describe all the constraints would require an explicit model of the transmission constraints, effectively requiring a comprehensive engineering model. We again see our approach as a complement, in that it relies on fewer assumptions about the transmission system and about CAISO mitigation behavior, which would bias the results if incorrect. Instead, our approach uses econometric tools and a novel methodology to measure the reduced form generation impacts of the closure. These results represent a combination of changes in bidding behavior, changes in CAISO market power mitigation decisions, and changes in transmission constraints.

4.2 Generation Curves by Category

The aggregate pattern of generation in Table 2 suggests that the majority of the response to the SONGS closure came from in-state natural gas generation, rather than imports or other fuel types. Additionally, we argue in Section 3.3 that the CEMS units we observe are the bulk of the in-state natural gas units that were able to respond to the SONGS outage. To formalize this argument, our first step is to estimate non-parametrically the relationship between system load and the generation within the categories defined in the CAISO data,

$$generation_{it} = \sum_b \left(\alpha_{bi} \cdot \mathbb{1}\{systemload_t = b\}\right) + \varepsilon_{it}. \tag{1}$$

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. We additionally separate thermal into two subcategories: thermal generation that does or does not appear in CEMS, where the latter is calculated as the difference between thermal generation reported in CAISO and that reported in CEMS.

We divide system load into bins of equal width. Figure 3 shows a histogram of hourly thermal load, using the same bin width definition as in the regressions. Panel A shows one year of the pre-period and Panel B the post-period. Total generation from CEMS unit shifts up substantially in the post-period to fill in for SONGS. Additionally, the distribution changes because of concurrent shifts, for instance in changes to hydro generation.

We do not include a constant in the regression, as the dummy variables sum to unity (we could equivalently drop one, but we are interested in the coefficient on each one rather than the relative coefficients). Without any other regressors, the coefficients α_{bi} give us the average generation for a category i when system load is at level b. If there are no unobservables, no ramping, etc. 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. Because there are no additional regressors, this is formally equivalent to calculating conditional means for different ranges of system load.

Graphs of the coefficients for the pre-period are shown in Figure 4. In each plot, the x-axis is the total generation from all CEMS units, divided into bins. The y-axis is 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. Panel A shows that, across all quantiles of load, the CEMS units are very responsive. Large-scale hydro (Panel B) is only somewhat responsive, which is a bit surprising. We thought this might be because 2011 had relatively high water supply, so we have also examined the generation curve for 2012. Though the overall level of hydro generation is lower in 2012, the slope is about the same.

The import curve (Panel C) is upward sloping, but only for relatively low load hours. Past median load, imports are essentially flat, suggesting that during high load hours only a very small part of the lost generation from SONGS would be met by imports. Nuclear and renewables are not upward sloping, as expected – the nuclear unit (Diablo Canyon) is baseload, and renewable generation is exogenously determined by weather.

4.3 Unit-Level Generation Regressions

To understand the plant-level changes in generation, we next estimate these regressions for each unit that appears in the CEMS data. The right-hand side bins are now defined over total generation by all California CEMS units. This is the *residual* demand, after generation from renewables, imports, and non-CEMS units has been subtracted from the total system load. We use this rather than total system load because we want to identify the ordering of the natural gas units. In particular, when evaluating changes from the pre-period to the post-period, we want to use only the variation caused by the SONGS outage, and not the variation caused by, for instance, changes to renewables or hydro. We discuss how this affects the interpretation of our results below.

Sample graphs of the coefficients from these unit-level regressions are shown in Figure 5. We show eighteen units: the six largest units 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 load. These units are generally new, large, and efficient. The combustion turbines in Panel B are turned on at higher levels of load and have much smaller capacity.

The boilers (Panel C), which are generally large and old, are turned on only at very high levels of system load.

We next estimate the unit-level generation regressions for two subsets of hours: before and after the SONGS closure. For the pre-period, we use data from 2010 and 2011, the two years leading up to the SONGS closure. Operating behavior from before 2010 is less likely to be a good counterfactual for after the SONGS closure, because of other changes over time. For instance, improved engineering and management practices mean that generating units are tending to operate more hours per year, with fewer unplanned outages. These changes tend to occur relatively slowly, but we nonetheless think it makes sense not to go back farther than 2010. For the post-period, we use data from February 2012 through January 2013. These are the first twelve months after the SONGS closure. While it would be interesting to examine longer-run changes in the market (which will include adaptation responses, such as new capital investment), our estimates would become less credible as we used data further into the future. In the Online Appendix, we include results through June 30, 2013 (the last available date of CEMS data). The out-of-order results are somewhat attenuated, as expected.

Thus the primary assumption we make 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. While 2012 was different in terms of natural gas prices, changes to non-thermal generation (such as hydro and renewables), and demand, we do not believe these changes affect the ordering of the natural gas units. As such, we can attribute moves up the ordering to the need to fill in for SONGS, and we can attribute re-ordering of units to the transmission constraints caused by SONGS. In the Online Appendix, we explore each concern in greater depth, concluding that our estimates are largely unaffected by them.

We begin our main sample on April 20, 2010; prior to that date, we do not observe CAISO generation data. Additionally, we drop a small number of days (fewer than ten) for which data from CAISO are incomplete. We drop a handful of generating units (n=4) which are owned by LADWP. As described above, LADWP maintains its own power generation and imports power from other states through long-term contracts, and is not part of the CAISO market. 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 2013). We explore entry and exit further in the Online Appendix.

4.4 Merit-Order and Out-of-Order Effects

We thus have a set of coefficients α for each of 22 bins at 184 generating units in 2 time periods, for a total of over 7,000 coefficients. We summarize them as follows. We define the "merit-order" change in generation at a given unit caused by the SONGS closure as: maintaining the ordering of units along the marginal cost curve, while requiring an additional 2,150 megawatt hours of generation to fill the SONGS gap. For convenience, we define the bin width as 2,150/2 = 1,075 megawatt hours, so that we can assume that system thermal load increased by two bins following the SONGS closure.[12] Then the "merit-order" change across all bins b and all generating units i in a geographic region (I_{North} or I_{South}) is:

$$\sum_{b>2} \sum_{i \in I} \left(\alpha_{bi}^{pre} - \alpha_{b-2,i}^{pre} \right) \cdot \theta_b^{post} \tag{2}$$

where θ_b^{post} is the fraction of hours that system load was in bin b.[13]

The "out-of-order" effect is the change in generation from the pre-period to the post-period, conditional on a given level of system load. To be precise, the out-of-order change across generating units i and bins b is:

$$\sum_{b} \sum_{i \in I} \left(\alpha_{bi}^{post} - \alpha_{bi}^{pre} \right) \cdot \theta_b^{post} \tag{3}$$

Summing these gives the total change across generating units i and bins b:

$$\sum_{b>2} \sum_{i \in I} \left(\alpha_{bi}^{post} - \alpha_{b-2,i}^{pre} \right) \cdot \theta_b^{post} \tag{4}$$

For ease of calculating standard errors, we estimate our main results at the regional, rather than generating unit level. This is numerically equivalent, since we are reporting the linear sum of coefficients across units within a region. The standard errors are clustered by sample month to allow for arbitary spatial correlation and to allow for serial dependence. To examine whether the monthly cluster was sufficiently long, we regressed the residuals on their lags. Beyond fifteen days, we estimate coefficients that are close to zero and not statistically significant.

[12] In robustness checks, we verify that results are similar for a bin width of 2,150 or 2,150/3.

[13] Note that this cannot be calculated for b=1 and b=2, since $b-2$ would be undefined. In our sample, these levels of thermal generation do not appear in the post period, so in practice $\theta = 0$. If they had appeared, one solution would have been to use $\theta_3 = \theta_1 + \theta_2 + \theta_3$.

Additionally, we evaluate the merit-order and out-of-order changes for subsets of hours when transmission constraints are most likely to bind. We consider two such subsets, each totalling approximately 5% 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 load hours when total CEMS generation was in 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 highly correlated with congestion as defined by the price differential between North and South.[14] Note that we use these definitions because they are exogenous; we do not condition directly on the price differential, as it is endogenous.

4.5 Main Results

Table 3 describes the effect of the SONGS closure on the geographic pattern of generation, reported in average hourly changes in megawatt hours. Panel A reports effects for all hours during the twelve months following the closure. The merit-order change in generation is similar between the North and the South: the point estimate is 892 in the South, and 944 in the North. The Central California column represents many fewer plants, and accordingly a smaller in-order change (300 MWh). The out-of-order change shows the displacement of generation from Northern generating units to Southern units. Relative to what we would have expected in a world without transmission constraints, the Southern units increased generation by 150 MWh, whereas the Northern units decreased 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.

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 out-of-order effect almost doubles, to a 237 MWh increase in the South and 260 MWh decrease in the North. In the 5% of hours with the highest level of system load (Panel C), the point estimate is an increase in the South of 431 MWh, and a decrease in the North of 381 MWh. As an alternative interpretation, the merit-order effect in high load hours is similar to an increase in capacity factor of seven percentage points. The out-of-order effect is comparable to increase in capacity factor of three percentage points in the South and a decrease of three percentage points in the North.

The results in Table 3 assume that the entire displaced SONGS generation (2,150 MWh) was met by in-state thermal units. As shown in Figure 4, imports are responsive at some levels

[14] They are also correlated with one another, with a simple correlation of 0.29.

of load to changes in demand. To account for this, we calculated the merit-order impact on imports of a shock to total load equal to 2150, using the same generation regression as in Figure 4. Averaging across all hours, we find that around 25% of the lost generation from SONGS was made up by imports. One could imagine adjusting the merit-order results in Panel A of Table 3 downward accordingly. For weekday summer afternoons and high load hours, however, we find a very small imports response, consistent with the visual evidence in Figure 4. On weekday summer afternoons, only 4 percent of the lost generation is made up by imports, and in high load hours it is less than 1 percent. While the merit-order effects depend on how responsive imports are, the out-of-order effects do not, as imports did not change transmission constraints. Further details and discussion are presented in the Online Appendix.

The table also reports standard errors. The merit-order changes are estimated with a high degree of statistical precision and all nine estimates are strongly statistically significant. The estimated out-of-order changes are less precise, reflecting that whereas the merit-order changes are estimated using the pre-period only, the out-of-order effects reflect differences in estimated coefficients between the pre-period and the post-period.

It would have been unusual to observe this magnitude and pattern of out-of-order effects due to chance alone. In the Online Appendix, we report results from a series of placebo tests aimed at providing some reassurance that these results are not driven by omitted variables or model misspecification. In particular, we repeat the analysis six times using the exact same specification, but with a different set of 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 out-of-order 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 out-of-order effects in other years, they tend to be driven by long outages. To demonstrate this, we show several diagnostics on the unit-level out-of-order effects. In the years with the largest out-of-order placebo effects, the standard deviation, skewness, and kurtosis are all substantially larger (in absolute terms) than in 2012, indicating large year-to-year changes in generation at a few individual plants rather than correlated changes in generation across many plants.

4.6 Impact on Costs

We next quantify the change in the total cost of production associated with these generation impacts. To do so, we must first calculate a marginal cost curve for each generating unit. As is common in the literature, we calculate marginal cost using information on heat rates, fuel prices, and variable operating and maintenance costs (VOM): $MC_i = heatrate_i \cdot fuelprice_i + VOM_i$. For the unit-level heat rate, we divide the total heat input over our time frame (in MMBtus) by the total net generation (in MWhs).[15] For the fuel price, we use the average post-period natural gas price in dollars per MMBtu, with separate prices for the North and South, from the Platts data described above. For VOM, we assume 3.02 $/MWh for combined cycle plants and 4.17 $/MWh for all other plants, following CEC (2010). The resulting marginal cost estimates range from $23.79 for generating units with favorable heat rates to $79.63 for units with high heat rates.

In Figure 6, we plot these marginal cost numbers for both the CEMS units and for other types of generation in California. For unit-level capacity, we use the maximum observed hourly generation in our sample. For the hydroelectric, renewable, and nuclear portions of this curve, we proxy for capacity with average hourly generation in the post-period (February 1 through January 31, 2013), using the CAISO production data. 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 the estimate of $7.08 per megawatt hour, the average fuel cost at nuclear plants reported in Table 8.4 of the EIA's *Electric Power Annual* (EIA 2012), plus $4.17 for VOM. Only in-state generation is shown. It is important to note that the estimates for natural gas units are specific to our time period, as they use average fuel prices for the twelve months following the closure. The marginal cost curve for other years with higher natural gas prices would be both higher and steeper. More details on the implicit assumptions underlying these calculations are given in Section 7.

We overlay on the marginal cost curve a histogram of total hourly generation in the post-period (February 2012 through January 2013). 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 25 $/MWh. In high load hours, however, the marginal unit is typically either a combustion turbine or a boiler (again, fueled by natural gas), with marginal cost around 40 $/MWh.

We next calculate the total cost of generation in each hour for each generating unit by multiplying cost per MWh by total generation. We next run regressions similar to the unit-level generation regressions: total cost is a function of total generation bins interacted with pre-period and post-period dummies. The advantage of using this regression is that we can

[15] This abstracts from ramping rates, as is common in the literature.

again decompose the total change in cost into merit-order and out-of-order changes. Results are given in Table 4. Taking a weighted average across all hours, the merit-order increase in total cost of thermal generation was $28,000 in the South, $8,000 in the ZP region, and $26,000 in the North - totalling over $61,000 statewide each hour. The average cost implied is approximately 29 $/MWh.

It is worth noting that this estimate of $61,000 does not account for a differential import cost. As described above, imports made up approximately 25 percent of the lost generation on average, across all hours. Given that the California marginal cost curve is quite elastic in most of these hours, 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 $61,000 to be close to the true merit-order change in total cost.

In addition to this merit-order increase in the total cost of thermal generation, the out-of-order changes are significant. While total cost increased by $6,900 in the South and $500 in ZP, it decreased by $3,000 at Northern generating units because of the decrease in quantity. Systemwide, this implies an increase of over $4,000 each hour coming from the out-of-order changes in generation. While lower-cost units were available in the North, they could not be used because of the transmission constraints.

Thus the total cost increase at thermal power plants statewide, including both merit-order and out-of-order effects, was over $66,000 each hour. This can be compared to total quantity multiplied by the average post-period price of 31.33 $/MWh, giving a naive calculation of $67,000 per hour. This is close to our estimate, because the supply curve is fairly elastic in the majority of hours. Thus the cost of the marginal generating unit is not very different from the cost of the inframarginal units. Next, using the EIA estimate of fuel costs at nuclear plants of 7.08 $/MWh for nuclear plants (EIA 2012) and a VOM of $4.17 implies that the marginal cost of generation at SONGS would have been around $24,000 each hour.[16] This difference in costs implied that the SONGS closure increased the cost of generation by about $369 million in the first twelve months (Table 5). Of this, the out-of-order portion is the cost associated with insufficient transmission capacity. This totals over $4,000 per hour – around $39 million over the first twelve months following the closure.

Panels B and C estimate the cost changes for weekday summer afternoons and high load hours, when transmission constraints are more likely to bind. The merit-order 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

[16]For nuclear plants, marginal costs are mostly fuel costs. Repair costs for the cracked steam generators are not marginal, but we consider these costs in Section 6.

generation impacts were larger. The out-of-order changes in total cost are also higher than in Panel A, reflecting a combination of larger out-of-order changes in generation and higher marginal costs. The system-wide total change in thermal costs is approximately $76,000 per hour on weekday summer afternoons, and around $83,000 per hour in high load hours.[17] For comparison, because the weekday summer afternoon average wholesale price was 50.86 $/MWh, a naive calculation of SONGS capacity multiplied by price would have implied a change in total cost of $109,000. The actual change in total cost is lower, because the marginal generating unit in these hours has a higher cost than the inframarginal units. Similarly, a naive calculation of P times Q for high load hours (Panel C) would have given an estimate of $112,000.

4.7 Impacts 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. The CEMS data provide hourly data by generating unit on emissions of various pollutants, as described in Section 3. We use the same type of regression as we used for the generation and cost changes, but now with CO_2 emissions, in tons, as the dependent variable. While California power plants are currently covered by a carbon cap and trade program, they were not yet covered in 2012. As a result, any increase in CO_2 emissions caused by the SONGS closure would not have been offset. We estimate an increase of 1,080 tons per hour.[18] For comparison, the average hourly total emissions at CEMS plants was around 4,200 tons in 2010 and 3,400 tons in 2011.[19] The central value of the social cost of carbon used by the federal government for regulatory impact analysis is 32 $/ton (in 2007$) (IWG 2013). For this cost of carbon, our estimates imply a social cost of the additional emissions of $331 million, in 2013$.

We also examine the impact on SO_2 and NOx emissions. For both pollutants, the increases we estimate are on the same order of magnitude (relative to baseline levels) as the CO_2 numbers. However, the economic significance is small for reasonable estimates of the social cost of SO_2 and NOx. Moreover, a portion of NOx emissions are capped in the RECLAIM

[17] As we describe above, imports did not substantially increase in the weekday summer afternoon and high load hours. As such, we expect our in-state calculations to be very close to the true total change in cost.

[18] We do not report the geographic breakdown nor the difference in high load hours, although they match what one would expect given the generation changes in Table 3. Since CO_2 is a long-lived, global pollutant, these breakdowns are not relevant.

[19] Hydro generation was large in 2011, which presumably lowered the total generation from thermal units and thus CO_2 emissions. These baseline numbers are for all units in CEMS, including those we drop when we construct our balanced panel. For our balanced panel, hourly emissions were around 2,900 tons in 2011.

market around the Los Angeles area, so some of these increases may have been offset by other sectors.

5 Plant-Level Impacts

We next present results disaggregated to the plant level. Table 6 shows the plants that were most affected by the SONGS outage. In Panel A, we show the plants with the five largest merit-order increases in generation. All five are large plants with low marginal cost. As Figure 6 shows, in most hours the equilibrium is at a fairly elastic portion of the supply curve, with costs around 25 $/MWh. Panel B shows the largest positive out-of-order increases, and Panel C the largest out-of-order decreases. The largest increases tend to be in the South and the largest decreases tend to be in the North, matching the aggregate results in Table 3.

The differences between the South and North are starker during hours when transmission constraints were most likely to bind. Table 7 shows the most affected plants during high load hours only. Results for weekday summer afternoons are similar and available in the Online Appendix. Not surprisingly, the merit-order increases are largest at plants with much higher marginal cost: around 40 $/MWh. In Panel B, the largest out-of-order increases are exclusively at Southern plants, as expected. Moreover, these are plants that were approximately on the margin: their marginal cost is comparable to the marginal cost of the plants in Panel A.

In Panel C, several of the largest out-of-order decreases are at plants in the North. There are two important exceptions, however. The two largest out-of-order decreases in high load hours were at plants in the South: Alamitos and Redondo, both owned by AES. These two large plants were on the margin in these high load hours: they appear in Panel A as plants with large merit-order changes. Moreover, given their location in the South, they would have been expected to have out-of-order *increases*. To illustrate the anomaly these plants represent, we show in Figure 7 the plant-level hourly out-of-order changes for high-load hours, separated by region. The AES plants are shown in orange circles, and all other plants are shown with black lines. While the other Southern California plants generally exhibit positive out-of-order effects, the AES plants are clearly unusual.

We view the AES out-of-order decreases as consistent with the exercise of market power. As it turns out, these two plants were operated through a tolling agreement with JP Morgan Ventures Energy Corporation, a subsidiary of JPMorgan Chase. The Federal Energy Regulatory Commission has alleged market manipulation by JP Morgan at these and other plants.[20] FERC 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. For details on the individual strategies, see FERC (2013). In 2013, JP Morgan agreed to pay a civil penalty of $285 million and to disgorge $125 million in alleged unjust profits.

It would be interesting to use our results to calculate the profit earned by AES by manipulating the market, potentially then comparing this number to the settlement with FERC. Several things prevent us from being able to do that. First, since JP Morgan was engaging in market panipulation in both our pre- and post-periods, we do not know whether the out-of-order decreases at Alamitos and Redondo are a result of unusually high generation in 2011 or withholding in 2012. Second, we do not observe a period when SONGS was closed but the Alamitos and Redondo plants were operating competitively. As data become available from post-settlement, it might be possible to do more here. Finally, much of the manipulation alleged by FERC was aimed at earning revenues through exceptional dispatch and other out-of-market operations, and we do not observe these payments.

We do, however, re-examine our main results in light of the FERC investigation. In Table 8 we present our main specification, with the three plants owned by AES separated from the other Southern plants. AES plants over this time frame were Alamitos, Redondo Beach, and Huntington Beach. AES and JP Morgan had tolling agreements for all three plants. As column (2) shows, the out-of-order increases in the Southern units are even larger than in Table 3, once the plants with alleged non-competitive bidding are separated out. We believe this validates our overall approach in two important ways. First, it shows that our out-of-order estimates do indeed show the effects of the transmission constraints between the Northern and Southern markets. Second, the out-of-order estimates can serve as a diagnostic tool, pointing to generating units where one might suspect non-competitive behavior.

[20] Wolak (2005) points out that regulatory oversight of electricity is different than for most goods, in that it is illegal to exercise unilateral market power. FERC is changed 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.

6 Discussion

The previous estimates speak to the benefits of transmission, but these must be compared with the costs. In this section we incorporate available estimates in the literature for the cost of upgrading transmission lines and other relevant points of comparison. We then step back and think more broadly about Southern California Edison's decision to close SONGS.

6.1 Benefits vs. Costs

Of the estimated \$369 million in increased generation costs, we attribute \$39 million to transmission constraints and other physical limitations of the grid. This reflects Southern plants operating too much, and Northern plants operating too little. Over twenty years with a 1.6% discount rate (Office of Management and Budget, 2013) this annual cost of \$39 million implies a present discounted value of \$677 million.

There are ways these transmission constraints could be relaxed. One approach would be to build an additional high-voltage (500-kV) transmission line along the existing 'Path 15' corridor, an 84-mile path connecting Northern and Southern California. The advantage of increasing capacity of existing transmission lines is that it avoids much of the siting challenges inherent in opening new corridors. A similar project in Path 15 was completed in 2004 and cost \$346 million.[21]

Another alternative would have been to add new generation capacity in Southern California. Construction costs for a conventional combined-cycle natural gas plant in California are about \$1100 per kilowatt (EIA 2013b), so to build a plant that could replace the entire 2150 megawatts from SONGS would cost about \$2.4 billion. This is considerably larger than the implied cost of the transmission constraints, but, of course, a new plant would have both relaxed the constraints and generated electricity.

There may also be lower-cost alternatives available for mitigating transmission constraints. Part of the challenge with the SONGS closure was voltage regulation. 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 that maintains voltage, making it possible to bring in more power produced

[21] See http://www.wapa.gov/sn/ops/transmission/path15/factSheet.pdf. We multiplied the construction cost by 1.13 to reflect year 2010 dollars.

far away. For example, in 2013, two generators at Huntington Beach Plant were converted to synchronous condensers, providing local voltage support. According to CAISO (2013a) the project cost $15 million, making this a relatively inexpensive project compared to capacity and generation additions.

The fact that the SONGS closure was unexpected sharpens the interpretation of our results, essentially allowing us to observe the California market with and without transmission constraints. But this comes at some cost in the form of external validity. Had the closure been anticipated, investments in capacity and generation could have been made in advance, potentially avoiding the regional imbalances altogether.

It is also important to distinguish between ex ante and ex post calculations. Our estimates provide ex post measures of the cost of the SONGS closure during the twelve months following the closure. They reflect natural gas prices, electricity demand, weather, and other market conditions from 2012. However, had these conditions materialized differently, the cost could have been much higher. An extended period of hotter-than-average weather or an outage at another major power plant could have resulted in price spikes or even blackouts.

6.2 The Decision to Close SONGS

An appealing feature of our analysis is that it provides some of the information necessary to evaluate the decision to close SONGS. When the decision was made to close the facility, it still had ten years left on its current operating license with the NRC.[22] Whether the decision to close makes sense or not depends on the value of the electricity that SONGS would have generated during this period, as well as on the fixed costs of repairing the plant and keeping it open.

We find that the SONGS closure increased generation costs by about $369 million during the first twelve months. Over ten years with a 1.6% discount rate this is $3.4 billion. If the transmission constraints and other physical limitations of the grid could be eliminated, the annual cost drops to $329 million, and the ten-year cost to $3.0 billion. Incorporating external benefits in the form of reduced carbon dioxide emissions would increase this value.

These benefits from keeping SONGS open must be compared against several significant costs. First, there was real uncertainty about the cost of required repairs, and even about whether SONGS would have ever been allowed to restart. When the decision was made to

[22]Reactor number two was licensed through February 2022, and reactor number three was licensed through November 2022. See NRC Digest.

close the plant the NRC had already warned SCE that it might be a year or more before a final decision would be made. Second, although the marginal cost of nuclear generation is low, its annual operations and maintenance costs are substantial, about $330 million per year.[23] Third, there are important external costs associated with operating a nuclear power plant. Some were concerned, for example, that SONGS' troubles signaled increased accident risk.

7 Conclusion

We find that the SONGS closure increased the private cost of electricity generation in California by about $369 million, and the social cost of emissions from generation by about $331 million, during the first twelve months. Of this, $39 million 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 that one company, in particular, may have acted non-competitively.

The analysis corroborates long-held views about the importance of transmission constraints in electricity markets (Bushnell, 1999; Borenstein, Bushnell and Stoft, 2000; Joskow and Tirole, 2000) and contributes to a growing broader literature on the economic impacts of infrastructure investments (Jensen, 2007; Banerjee, Duflo and Qian, 2012; Borenstein and Kellogg, 2014; Donaldson, Forthcoming). Infrastructure facilitates trade and reduces price dispersion, but it also affects market structure, and this is true not only for electricity but also for a broad range of tradable goods (Ryan, 2013).

Our results also illustrate the challenges of designing deregulated electricity markets. Wolak (2014) 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, so 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

[23] The Cost of Generation Model from CEC (2010) assumes an annual fixed O&M cost of 147.7 $/kW-yr, in 2010 dollars. We multiplied this by SONGS' capacity of 2150 MW and we translated into current dollars.

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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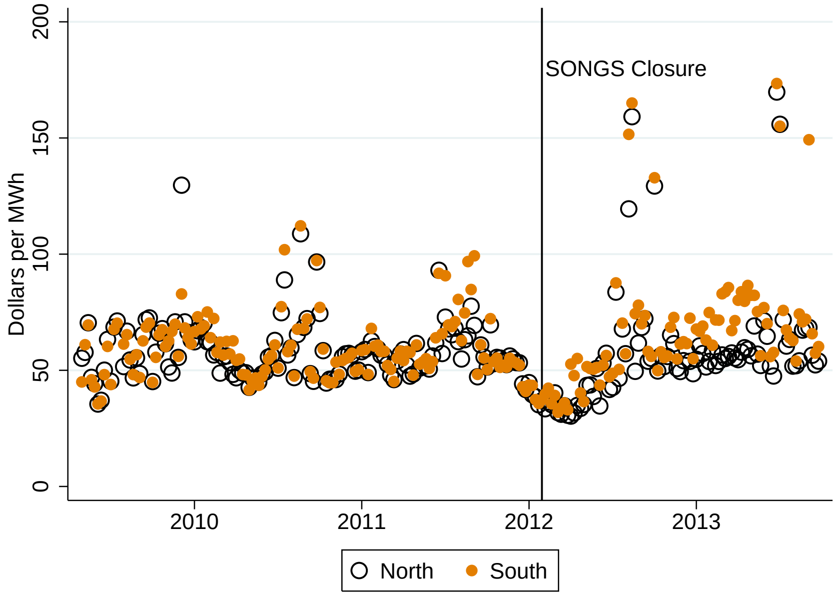
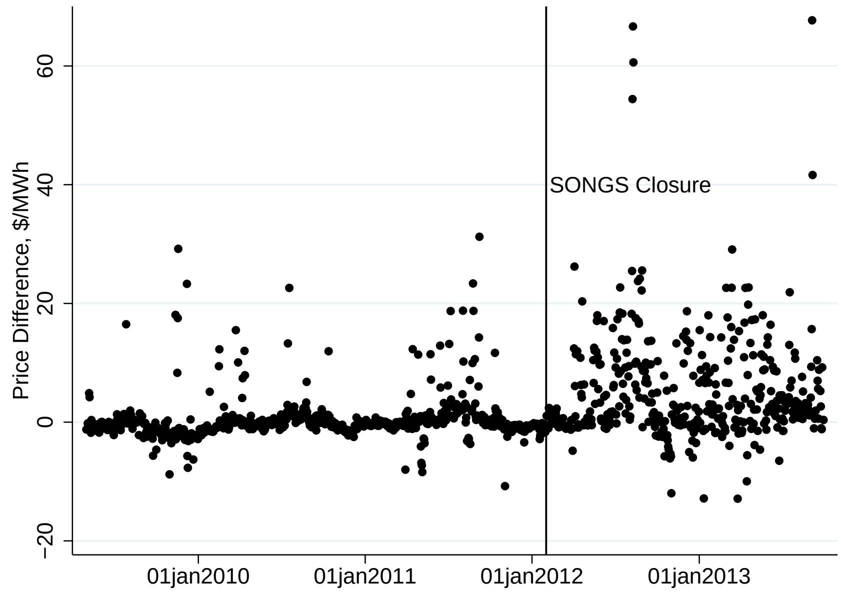
Figure 1: Weekly Maximum Prices, South versus North



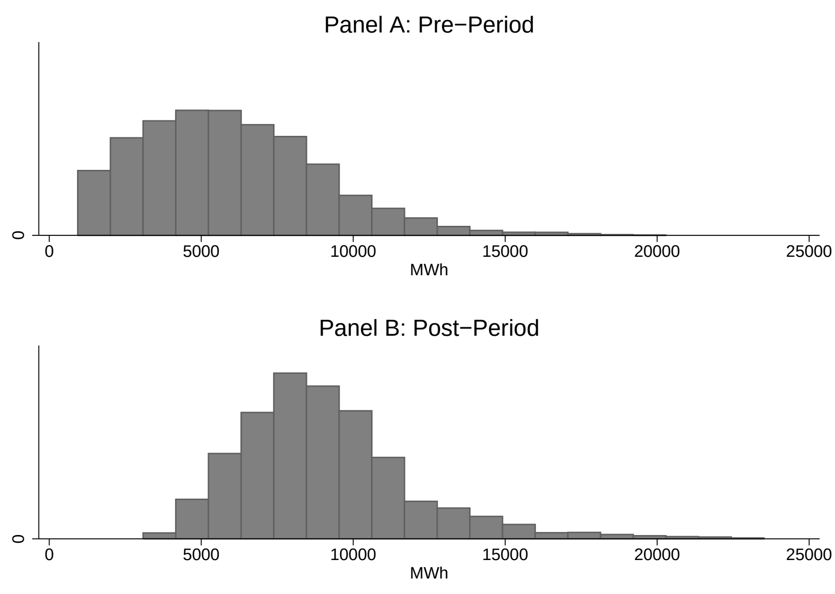
Note: The prices are for the maximum hourly price in a given week for the North and the South. The vertical line shows the week the second SONGS unit went down (February 2012). One outlier in 2009, with both North and South prices greater than 400, has been dropped. Prices are in $/MWh. North and South are defined by the Path-15 transmission interconnection.

Figure 2: Price Differential, South versus North



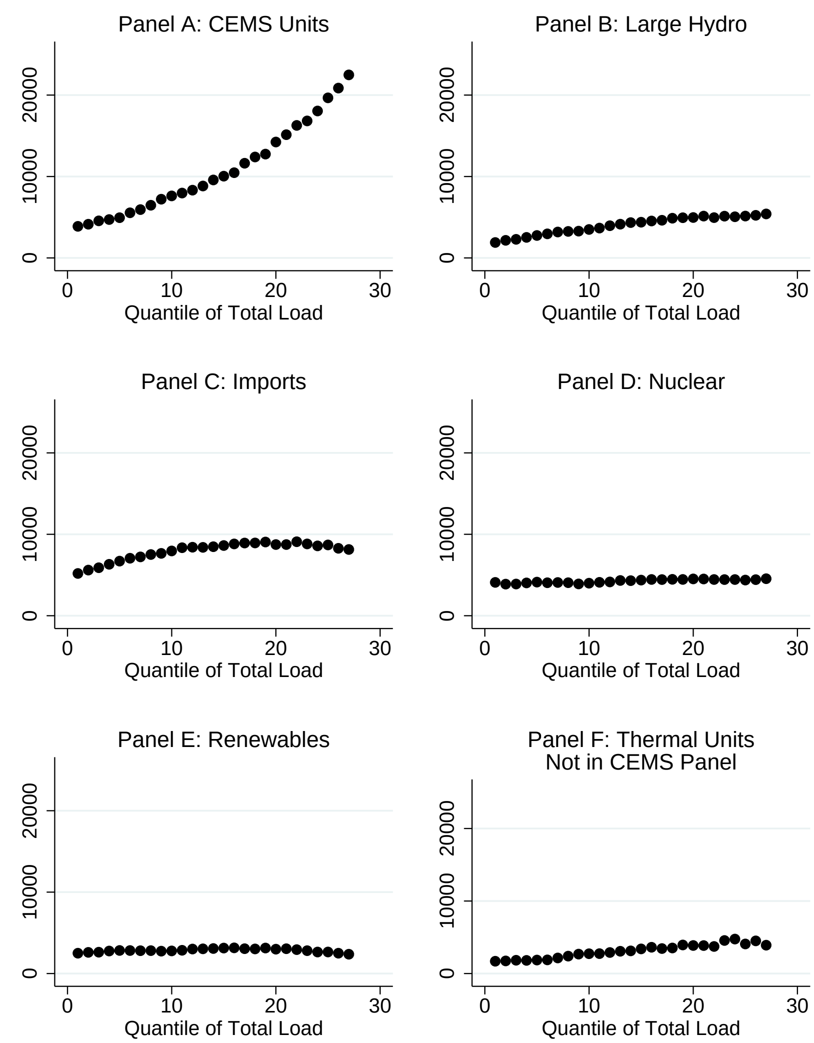
Note: This figure describes daily price differentials at 3 pm between May 2009 and September 2013. Weekends are excluded. For each day, we calculate the price difference between the South and North. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Figure 3: Histogram of Hourly Load



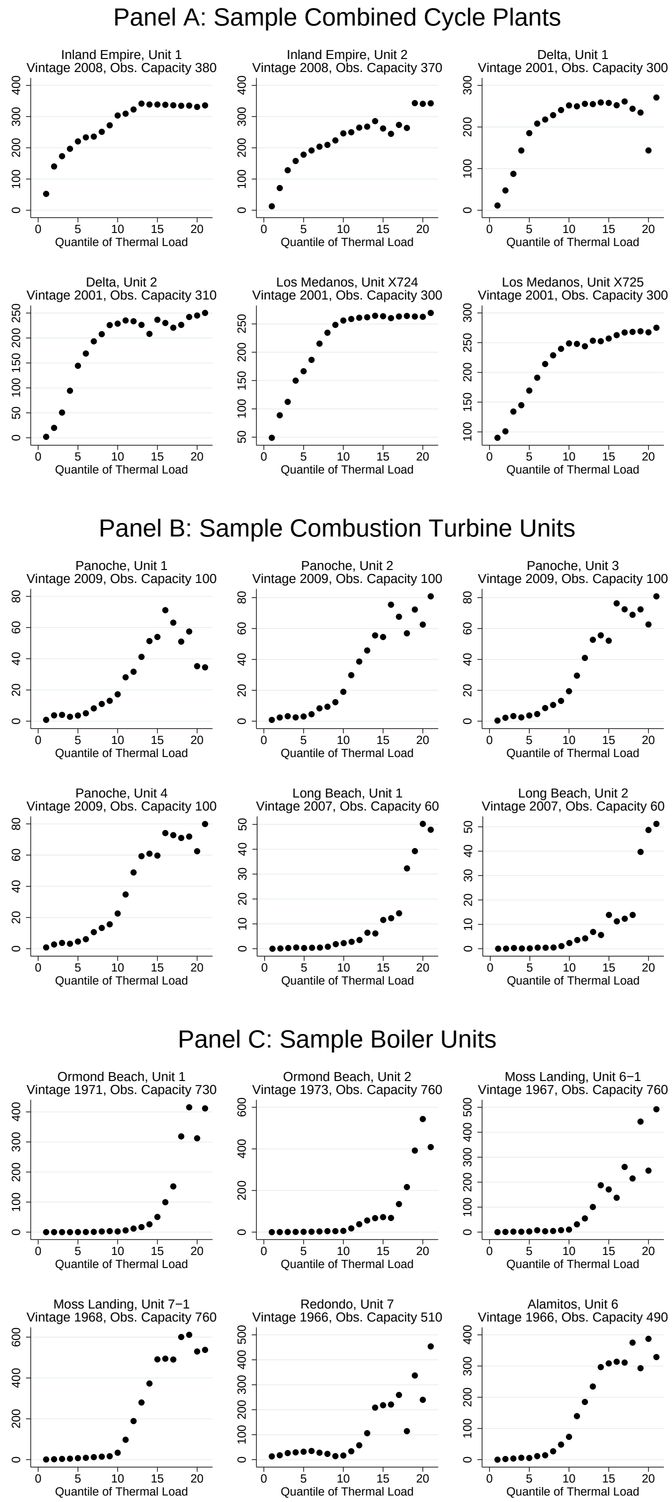
Note: This figure shows a histogram of total hourly generation from CEMS units in the year leading up to the SONGS closure (Panel A) and in the year following the closure (Panel B). The shift to the right in Panel B reflects both the closure of SONGS and concurrent changes in non-thermal generation (especially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

Figure 4: Pre-Period Load Regressions by Fuel Type



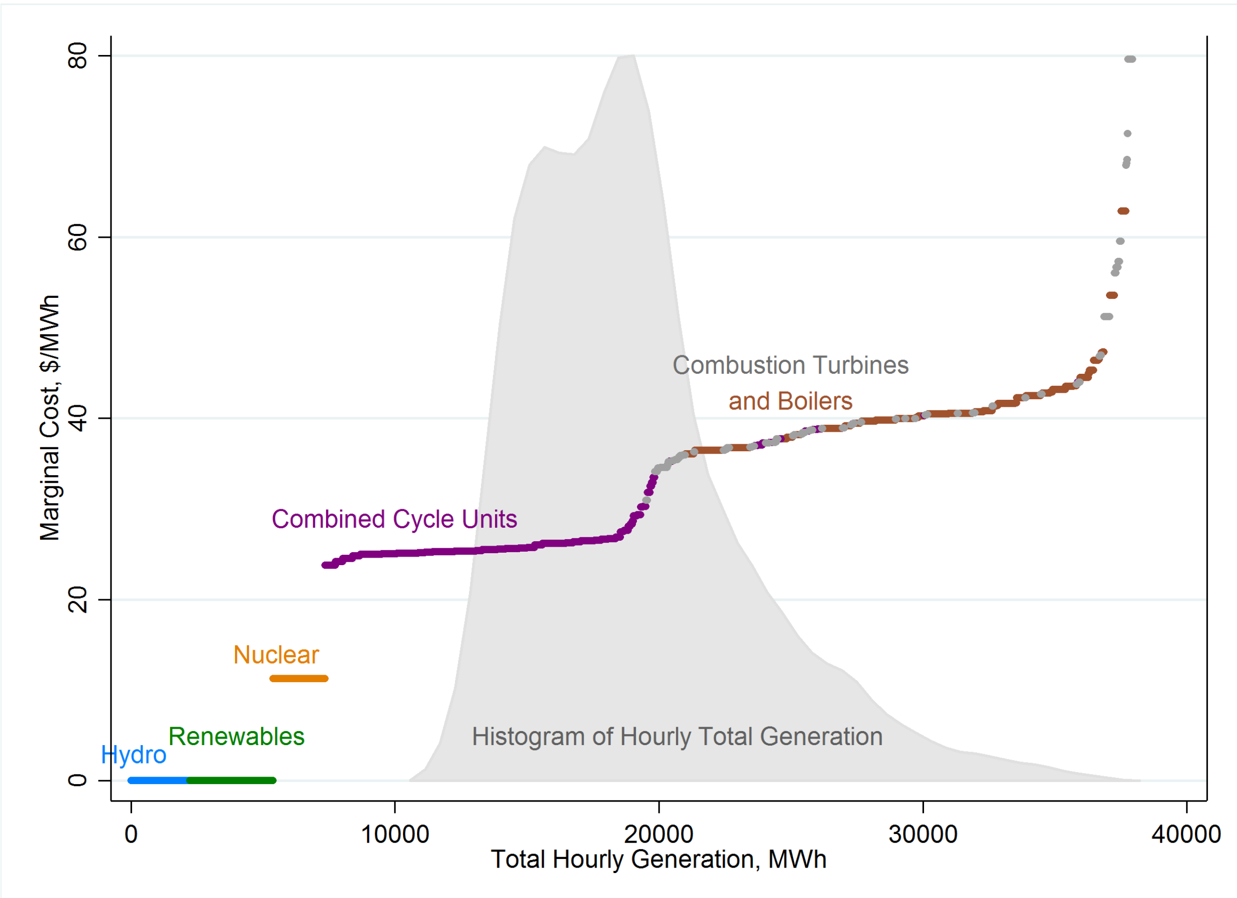
Note: These figures plot the coefficients from six regressions, using hourly generation data from CEMS and CAISO. The x-axis shows the quantile of total generation from all sources. The y-axis shows the average generation, in MWh, for that category of generation. Data are from the two years prior to the closure of SONGS. For the non-CEMS thermal units in Panel F, we have subtracted total CEMS generation in our balanced panel from the total thermal generation reported in CAISO data. Details on the regression estimation are given in the text.

Figure 5: Sample Pre-Period Unit Generation Regressions



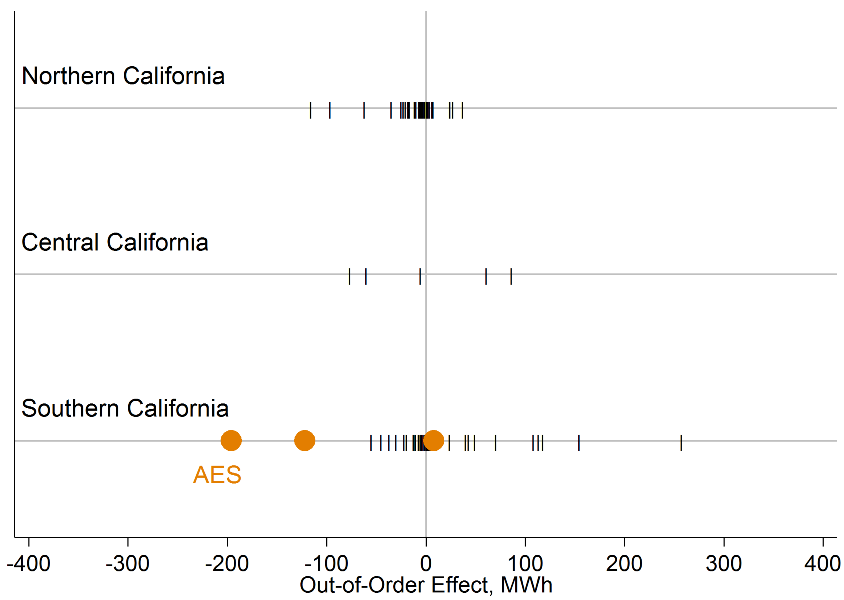
Note: These figures plot the coefficients from 18 unit-level generation regressions, for the six largest units within three technology types. The x-axis shows the quantile of total generation from all units. The y-axis shows the average generation, in MWh, at the individual unit. Data are from the two years prior to the closure of SONGS. Details on the regression estimation are given in the text.

Figure 6: 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. Imports are not included. To construct marginal cost for natural gas units, we use unit-specific heat rates, the average natural gas price (separated by region), and California Energy Commission estimates for variable O&M costs. For details, see the text. For the capacity of natural gas units (i.e. the width of each step), we use the maximum observed hourly generation in our sample. For hydro, renewables (including wind, solar, geothermal, and small hydro), and nuclear capacity, we use average hourly generation in 2012. For the marginal cost of nuclear generation, we use an EIA estimate of fuel costs of 7.08 $/MWh and VOM of 4.17 $/MWh. Biomass/biogas are not shown, as marginal cost numbers are not available. This 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.

Figure 7: Plant-Level Out-of-Order Changes, in High Load Hours



Note: This figure plots the plant-level hourly average out-of-order change by region, with AES-owned plants shown in solid orange circles. The regional totals are shown with hollow circles. Details on the calculations are given in the text.

Table 1: California Net Electricity Generation By Source in 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 includes generation from all electric generating plants larger than one megawatt. The table describes 2011 net generation for plants operating in California. Out-of-state generation, including electricity imports, are excluded. “Other Fossil Fuels” includes petroleum coke, distillate petroleum, waste oil, residual petroleum, other gases, and other (including nonbiogenic municipal solid waste). “Other Renewables” includes wood and wood waste, and municipal solid waste and landfill gas.

Table 2: California Electricity Generation, 2011-2012

	Average Monthly Generation, Million MWh 2011	Average Monthly Generation, Million MWh 2012	Change
Panel A: By Fuel Type, EIA Data			
Natural Gas	7.41	10.09	2.68
Wind	0.65	0.83	0.18
Geothermal	1.05	1.11	0.06
Solar (PV and Thermal)	0.07	0.12	0.04
Other Renewables	0.50	0.53	0.02
Coal	0.17	0.13	-0.03
Other Fossil Fuels	0.29	0.21	-0.08
Hydroelectric	3.54	2.21	-1.33
Nuclear	3.06	1.54	-1.51
Panel B: By Sector, Natural Gas Only, EIA Data			
IPP Non-Cogen	2.63	4.51	1.88
Electric Utility	2.24	2.98	0.73
Industrial Non-Cogen	0.03	0.10	0.07
IPP Cogen	1.37	1.43	0.06
Commercial Non-Cogen	0.02	0.02	0.00
Commercial Cogen	0.14	0.12	-0.01
Industrial Cogen	0.99	0.93	-0.06
Panel C: By Type, CAISO Data			
Thermal	6.12	8.47	2.35
Imports	5.45	5.77	0.32
Renewables	2.11	2.25	0.14
Large Hydro	2.47	1.58	-0.89
Nuclear	3.07	1.55	-1.51

Note: This table reports the average monthly net generation in California in 2011 and 2012, measured in million MWh. As described in Section 3.1, the EIA data describe all U.S. generating facilities with more than one megawatt of capacity. Here we report generation from all facilities in the state of California. In Panel A, "Other Renewables" includes wood and wood waste, and municipal solid waste and landfill gas. "Other Fossil Fuels" includes petroleum coke, distillate petroleum, waste oil, residual petroleum, other gases, and other (including nonbiogenic municipal solid waste). 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.

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

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change in Net Generation (MWh)	892	300	944
	(18)	(15)	(18)
Out-of-Order Change in Net Generation (MWh)	150	20	-140
	(73)	(66)	(79)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change in Net Generation (MWh)	1068	259	822
	(47)	(17)	(39)
Out-of-Order Change in Net Generation (MWh)	237	76	-260
	(144)	(61)	(119)
	Panel C: High Load Hours		
Merit-Order Change in Net Generation (MWh)	1207	174	753
	(44)	(30)	(35)
Out-of-Order Change in Net Generation (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 Represented (MW)	15,922	2,887	11,776

Note: The sample includes electric generating units that report to the EPA Air Market Program's *Continuous Emissions Monitoring System* within particular geographic areas as indicated by the column headings. We exclude generating units that enter or exit during our sample period, to focus on a complete panel of continuously reporting units. Our sample includes all hourly observations between April 20, 2010 and January 31, 2013. The merit-order calculation gives the increase in generation at marginal units, assuming 2,150 MWh are needed to make up for the lost generation from SONGS. The out-of-order calculation gives the difference between actual and expected generation, as explained in the text. Standard errors (in parentheses) are clustered by sample month. In Panel B, Weekday Summer Afternoons include the hours 2 p.m. to 5 p.m. in months June through September. In Panel C, High Load Hours are defined as hours when total CEMS generation was in the 13th quantile (greater than 13,837 MWh); results are qualitatively similar with other cut-offs. For unit-level capacity, we proxy with maximum observed generation in our sample; total capacity is the sum across units. The three geographic zones are defined by the Path-15 and Path-26 transmission interconnections.

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

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change in Total Cost ($000's)	28.0	7.7	26.0
	(0.6)	(0.4)	(0.5)
Out-of-Order Change in Total Cost ($000's)	6.9	0.5	-3.0
	(2.9)	(1.7)	(2.4)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change in Total Cost ($000's)	40.8	7.3	26.9
	(1.6)	(0.5)	(1.4)
Out-of-Order Change in Total Cost ($000's)	8.6	1.4	-8.9
	(5.0)	(1.6)	(4.2)
	Panel C: High Load Hours		
Merit-Order Change in Total Cost ($000's)	48.8	5.6	27.2
	(1.8)	(0.8)	(1.4)
Out-of-Order Change in Total Cost ($000's)	16.0	-0.5	-14.2
	(4.7)	(1.7)	(4.7)
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 Represented (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 generating cost, rather than the change in generation. As we explain in the text, this includes changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M.

Table 5: Total Impact of SONGS Closure

	Impact during the 12 Months following Closure, Millions of $
Merit-Order Increase in Thermal Generation Costs	541 (3.0)
Out-of-Order Increase in Thermal Generation Costs	39 (10.5)
Net Increase in Generation Costs	369 (10.0)
Change in External Carbon Costs	331 (8.0)

Note: The "out-of-order" increase is the effect of insufficient transmission capacity. The "net increase" combines the merit-order and out-of-order changes to thermal generation costs, then subtracts annual generation costs at SONGS. This number thus represents the increase in generation costs caused by the SONGS closure. As we explain in the text, these generation costs includes changes in fuel expenditures and other marginal costs, but not capital costs or fixed O&M. For comparison, annual fixed O&M at nuclear plants is around $330 million per year. Carbon is valued at $35/ton, as described in the text. All dollar amounts in year 2013 dollars.

Table 6: Most Affected Plants, All Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Order Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	26/26/27/27/36/37	2541	227	59
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	25/25/25/26	1066	168	100
3	Pastoria	Calpine	Comb Cyc	SP15	25/25/25	764	142	-37
4	Delta	Calpine	Comb Cyc	NP15	26/26/26	896	126	25
5	Mountainview	SCE	Comb Cyc	SP15	25/25/25/25	1068	126	3
			Panel B. Out-of-Order Increases, Top Five					
1	Otay Mesa	Calpine	Comb Cyc	SP15	25/26	596	54	143
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	25/25/25/26	1066	168	100
3	Cabrillo I Encina	NRG	Boiler	SP15	40/40/41/43/44	954	23	87
4	High Desert	Tenaska	Comb Cyc	SP15	39/39/39	492	91	82
5	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	26/26/27/27/36/37	2541	227	59
			Panel C. Out-of-Order 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	24/25	564	101	-94
4	Gateway	PGE	Comb Cyc	NP15	26/27	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. 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.

Table 7: Most Affected Plants, High Load Hours

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Order Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	26/26/27/27/36/37	2541	251	-62
2	AES Alamitos	AES	Boiler	SP15	40/41/41/43/45/46	1934	238	-196
3	AES Redondo	AES	Boiler	SP15	40/43/54/63	1348	130	-122
4	El Segundo	NRG	Boiler	SP15	40/42	658	130	113
5	Cabrillo I Encina	NRG	Boiler	SP15	40/40/41/43/44	954	124	154
			Panel B. Out-of-Order Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	35/37/37/38/40/42	636	33	257
2	Cabrillo I Encina	NRG	Boiler	SP15	40/40/41/43/44	954	124	154
3	Otay Mesa	Calpine	Comb Cyc	SP15	25/26	596	10	117
4	El Segundo	NRG	Boiler	SP15	40/42	658	130	113
5	Ormond Beach	NRG	Boiler	SP15	39/40	1490	98	108
			Panel C. Out-of-Order Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	40/41/41/43/45/46	1934	238	-196
2	AES Redondo	AES	Boiler	SP15	40/43/54/63	1348	130	-122
3	Panoche	Energy Investors Fund	Combust Turbine	NP15	34/35/35/35	412	53	-116
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/37	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. Marginal cost numbers are from authors' calculations, described in the text. Capacity in MW is the maximum observed capacity in our sample. High load 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.

Table 8: 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			
Merit-Order Change in Net Generation (MWh)	110	781	300	944
	(15)	(15)	(15)	(18)
Out-of-Order Change in Net Generation (MWh)	-32	182	20	-140
	(60)	(53)	(66)	(49)
	Panel B: Weekday Summer Afternoons			
Merit-Order Change in Net Generation (MWh)	339	729	259	822
	(31)	(27)	(17)	(39)
Out-of-Order Change in Net Generation (MWh)	-311	548	76	-260
	(94)	(105)	(61)	(119)
	Panel C: High Load Hours			
Merit-Order Change in Net Generation (MWh)	455	752	174	753
	(42)	(34)	(30)	(35)
Out-of-Order Change in Net Generation (MWh)	-310	742	4	-381
	(127)	(111)	(57)	(129)
Observations	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 Represented (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 JPMorganChase had tolling agreements for all three plants.

Appendix: Potential Confounders

A1.1 Preliminary Discussion

In this section we evaluate the potential for confounding factors to be influencing our results. We are interested, in particular, in potential bias of our main estimates of merit order and out-of-order changes. We consider natural gas prices, changes to non-thermal generation, entry and exit, imports, and demand. Although it is important to go through these potential concerns carefully, we end up concluding that overall our estimates are likely to be largely unaffected by these confounders.

Before discussing the specific concerns, it is useful to clarify exactly what we mean by bias. Consider, for example, our estimates of merit order effects. Conceptually, what we wish to capture is the change in generation from the SONGS closure that would have resulted in a market with no transmission constraints and holding everything else constant. We build this counterfactual by constructing the unit-level generation curves using data from *before* the closure, and then moving up the curve by the amount of lost generation.

Thus, in some sense, no change to the market in 2012 could "bias" these results. Our merit-order estimates are constructed using pre-closure data only, and so they provide predicted changes in generation given the market conditions *prior* to 2012. Since there is no information from 2012+ in these estimates, it does not make sense to talk about them being biased by what happened in 2012. Instead, it is reasonable to ask whether the 2010 and 2011 data provide a good representation of what the ordering of plants would have been had SONGS not closed, and in this section, we show that they do provide such a representation.

The out-of-order effects are easier to think about. Conceptually, we want these estimates to reflect the *difference* between actual generation and the generation we would have observed in a market with no transmission constraints. We interpret these out-of-order effects as the causal impact of the transmission constraints and other physical limitations of the grid, as well as any increased exercise of market power that goes along with it.

There is an additional consideration: we are attributing the out-of-order effects to transmission constraints, and we are attributing the increase in transmission constraints 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 that these out-of-order effects are biased by other factors influencing transmission constraints or by other unmodeled changes in the market between the pre- and post- periods.

In the subsections that follow we discuss the changes in the California electricity market in 2012 and how they might be biasing our estimates or changing the way they should be interpreted. Subsections are organized into groups. We look first at natural gas prices, then changes to non-thermal generation, entry and exit, imports, and finally, electricity demand.

A1.2 Changes in Natural Gas Prices

Natural gas prices were more than 20% 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.

It is also natural to ask whether this price change could somehow bias our estimates of merit order and out-of-order changes. In this section we evaluate several potential concerns and, at the same time, discuss closely related questions about changes in the price of permits for Southern California's cap-and-trade program for nitrogen oxides (NOx). 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 describe implicitly an ordering of plants along a 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 appear at the top 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 out-of-order effects. For example, we could see a generator that is operating more because of a change in the merit order, and misinterpret this as the impact of transmission constraints.

Although this is certainly possible, there are several reasons why we would *not* expect large changes in the merit order. 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. In addition, nuclear, 'run-of-the-river' hydro, geothermal, wind, and solar all operate at extremely low marginal cost, thus are always ahead of natural gas in the queue. Moreover, 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.

We say 'largely unaffected' because marginal cost also depends on NOx emissions and variable operations and maintenance, which vary across plants, but these components are small compared to the cost of fuel so that the merit order is close to a monotonic ranking of plants by heat rate. Take NOx prices, for example. 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 have had any affect on the ordering of the plants. In our data, the median emissions rates for the Los Angeles area plants is 0.2 pounds per MWh, and the mean rate is 0.4. Prices for NOx permits ranged from 1160 to 2400 $/ton in 2010-2012, implying that NOx credit payments make up only a small portion of the plants' marginal costs.[24]

A more subtle concern would be differential changes in natural gas prices between the North and South. However, as can be seen in Figure A1, the 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 South increased from the pre- to post-period approximately 2% more than in the North. This is a relatively small change, so we would not expect it to have much impact on the ordering of plants.

A1.3 Changes to Non-Thermal Generation

Between 2011 and 2012 there were significant changes in electricity generation from hydro and renewables. Perhaps most importantly, 2012 was an unusually bad year for hydroelectric generation. The snowpack in 2012 was only half of the historical average level, and total hydroelectric generation in 2012 was less than 2/3rds generation in the previous year.[25] At the same time, there were also *increases* in wind and solar generation. Almost 700 megawatts of wind and solar capacity were added in 2012, resulting in large percentage increases in generation from wind and solar.[26] This section discusses how these changes in non-thermal generation could potentially be impacting our estimates or affecting how the

[24]The mean marginal cost would therefore be less than $0.50, 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 is 5 pounds per MWh. We are exploring the potential impact of these outliers in simulations.

[25]For historic snowpack levels see http://cdec.water.ca.gov/cdecapp/snowapp/sweq.action.

[26]See CAISO (2013b) for details. Geothermal and other renewables experienced essentially no change between 2011 and 2012.

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. While new 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 merit-order effects using *net* system load. When calculating load for our unit-level regressions, we start with system load but then *subtract* from it all electricity generation from these non-thermal resources. This makes sense for wind, solar, and non-dispatchable hydro. Their marginal cost of operation is near zero, and they are always included at the top of the merit order. The same could be said for electricity generation from California's one other nuclear power plant, Diablo Canyon.

Dispatchable hydroelectric generation is somewhat harder to think about, but also unlikely to be affecting our results. Year-to-variation in precipitation determines total hydroelectric generation, but operators have some flexibility as to *when* these resources are utilized. Short-run generation decisions are determined by a complex dynamic optimization problem. Operators responding to current and expected market conditions, trading off between current prices and the shadow value of remaining reservoir. None of this is particularly problematic for our analysis because operators are presumably behaving similarly both before and after the SONGS closure. Moreover, the generation curves in Figure 5 indicate only a modest amount of intertemporal substitution toward high load periods.

A related question is how changes in non-thermal 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 out-of-order effects to transmission constraints caused by the SONGS outage. Although this is an important consideration, the decrease in hydroelectric generation would have, if anything, made transmission constraints *less* likely to bind. Hydroelectric plants are located primarily in the North,[27] so the decrease in hydroelectric generation in 2012 would have reduced the need for North-South transmission.

In addition, the changes in wind and solar generation, while large percentage increases, represent small changes when compared to the entire market. Wind and solar generation

[27] According to CAISO (2013d), approximately 80% of summer capacity is in the North.

statewide increased by 0.18 million, and 0.04 million Mwh per month, respectively, in 2012. Total monthly generation in California in 2012 was 16.77 million Mwh, so these increases combined represent only about 1% of total generation. Moreover, most of the new capacity was in the South, so if anything, these additions would have made transmission constraints *less* likely to bind.

A1.4 Entry and Exit

From 2010 to 2012, a number of generating units opened or closed, and in this section we discuss the impact of this entry and exit on the interpretation of our estimates. Our main results focus for simplicity on a balanced panel of units, restricting the sample to those units that were continually in service between April 2010 and December 2012. Excluding units that enter and exit raises two potential concerns.[28] 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 it affected transmission congestion. This would then bias our out-of-order effects.

We argue that endogenous entry and exit are not a concern given the short time horizon we consider. 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 thirteen units that opened in 2012.[29] Altogether, these units accounted for 4% of CEMS generation in 2012. 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.[30] It is true that in the long run, we would expect endogenous entry, but 2012 is still much too early.

Moreover, the entry and exit that did occur, even if it impacted transmission congestion, cannot explain the merit-order effects that we estimate.[31] Net entry was larger in the North

[28]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 confounder our results only if it were systematically different between the North and the South.

[29]Six units closed in 2010, and 12 units opened in 2010 and 2011. These could not have been caused by the SONGS closure, which was not yet expected.

[30]It is possible that new entry may have been accelerated by the SONGS closure, but we are unaware of any specific cases.

[31]However, note that we are unable to calculate the merit-order and out-of-order effects at the plants that enter or exit. Since we do not have a full time series of generation at these units, we cannot construct the proper counterfactual. As such, our results are limited to those plants that operate continuously.

than the South, by approximately 100 MWh each hour. This could change congestion in the same direction as the closure of SONGS. However, the difference in net entry between the South and North is smaller than the change in generation from large-scale hydro. As such, the overall impact of these combined changes to generation (from net entry, large-scale hydro, and other renewables) would have been to partially relieve congestion caused by the closure of SONGS.[32]

A1.5 Imports

Imports make up 30% of total electricity supply in California. In calculating our "merit order" 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. During the hours in which equilibrium occurs along the steep part of the marginal cost curve, there are questions about whether there was available interstate transmission to bring in additional out-of-state supply.

Empirically, the elasticity of supply for imports appears to be relatively low. We estimated an equation similar to our unit-level generation regression in equation (1), by regressing imports on bins of total California system load. We use data from the entire period (April 20, 2010 to January 31, 2013) to improve precision, but results are similar if we consider only the pre-period or only the post-period. Imports increase with system load, but not very much, and most of the increase occurs at relatively low load quantiles. Moreover, above the median load, there is essentially no observable increase in imports. Averaging across all hours, imports increase by an average of 519 megawatt hours when total load increases by 2,150 MWh. This is equivalent to 25% of the lost generation from SONGS. This suggests that we could reduce our merit-order estimates in Panel A of Table 3 by 25%. The regional pattern of impacts would still be similar, but all of the estimates would only be about three-quarters as large.

Interestingly, the change in imports during weekday summer afternoons and high load hours

[32]For this calculation, we assume that 80% of the fall in hydro generation was from Northern resources. We also make the conservative assumption that the entire increase in solar and wind generation was from Southern resources.

was much lower. During weekday summer afternoons, imports in 2012 increased on average by only 90 megawatt hours, and during high load 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 the fact 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. From the perspective of interpreting our results it means that the estimates in Panels B and C of Table 4 are approximately correct. If we think imports in 2011 are a good counterfactual, then to incorporate imports we would want to reduce our estimates in these panels by only 4% and 1%, respectively, to reflect the relatively small portion of the lost generation from SONGS that appears to have been met with imports.

A1.6 Electricity Demand

Statewide demand for electricity was slightly higher in 2012 than 2011 due to warm weather. We calculate our "merit order effects" using the distribution of system load in 2012, so our estimates reflect this higher overall level of load. 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.

The increase in electricity demand also raises questions about external validity. 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 merit-order effects by moving along the generation curves by 2,150 megawatt hours, the entire lost generation from SONGS. This is correct only if 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. Moreover, most estimates of the price elasticity of demand suggest that even in the medium-term, demand is not very elastic.[33] Thus evaluating the change in supply required to make up the entire 2,150 megawatts hours 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: the PG&E, SCE, and SDG&E territories. In graph A2, we show the total weekly load 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 graph A3, 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 out-of-order results could have been driven by the changes in demand, we estimate our main results conditioning on the load difference between North and South. Specifically, we calculate the difference between South (SCE plus SDG&E) and North (PG&E), then construct a series of equal-width bins. These bins are interacted with the load bins in the unit-level generation regressions.[34] The merit-order results (available upon request) are qualitatively similar to (and not statistically different from) those in Table 3. The point estimates of the out-of-order results are around 10 to 20% 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. Unfortunately, we are unable to construct a complete counterfactual for the pre-period under high levels of Southern demand.

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

[34] These regressions drop observations in bins for which there is no pre-period coverage.

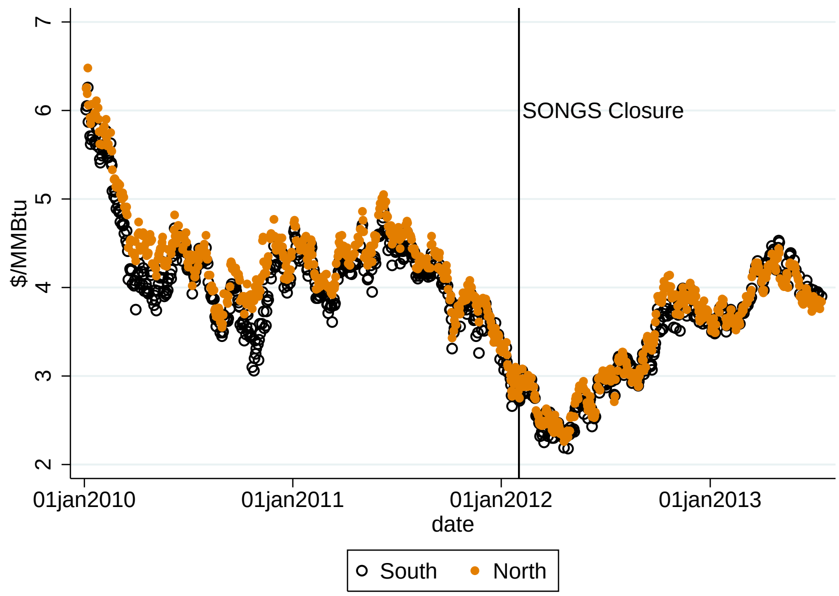
A1.7 Placebo Tests

To provide further evidence that the observed out-of-order 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 (2007, 2008, etc). Figure A4 shows the out-of-order changes for each "placebo" regression, with separate results (as in our main analysis) for all hours, weekday summer afternoons, and high load hours.

The figure shows that some of the estimated out-of-order effects from other years are similar in size to the estimates for 2012. In 2007, for instance, the South saw positive out-of-order 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 A5, we again show six placebo tests, but AES has been dropped. The large positive changes in the South and negative changes in the South are more apparent than in the previous figure.

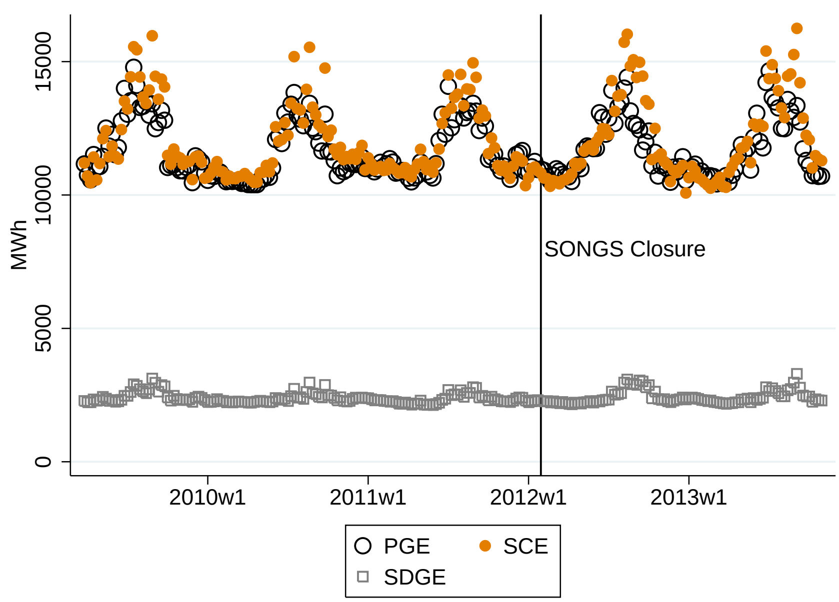
Moreover, closer inspection of the out-of-order results in other years shows that they are largely driven by extended outages at single plants, rather than by correlated changes across plants. To demonstrate this, Figure A6 shows a series of statistics from the unit-level out-of-order changes in the placebo tests. In particular, we calculate the standard deviation, skewness, and kurtosis of the unit-level changes. For years with the largest out-of-order changes (especially 2007 and 2009), the presence of outliers is clear in these diagnostics. Those years have higher standard deviations, skewness (in absolute terms), and kurtosis than our main sample, indicating the presence of outliers. Overall, these placebo test results indicate that the pattern of results we see in 2012 is indeed unusual.

Appendix Figure A1: Natural Gas Prices, by Region



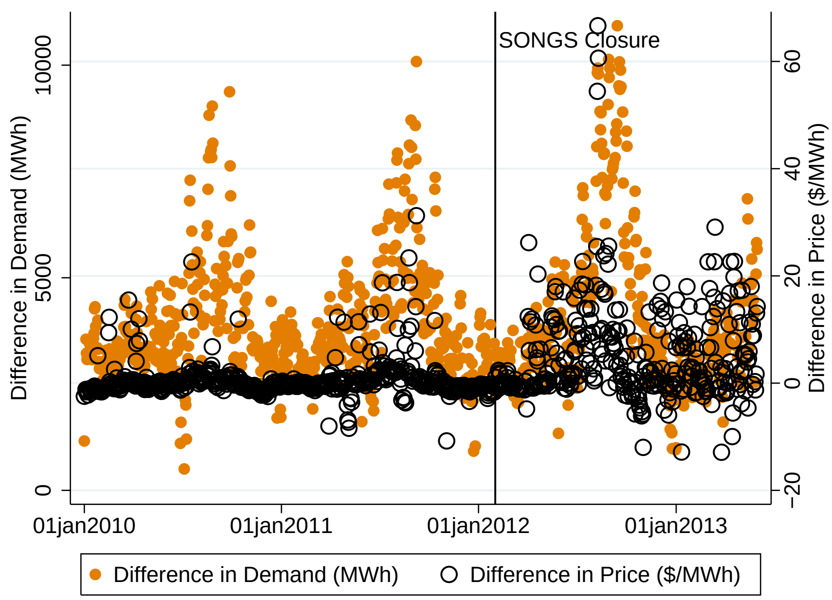
Note: This figure plots daily natural gas prices, in $/mmbtu, for Northern California (PGE citygate) versus Southern California (SCG citygate). Data are from Platts Gas Daily.

Appendix Figure A2: Regional Load



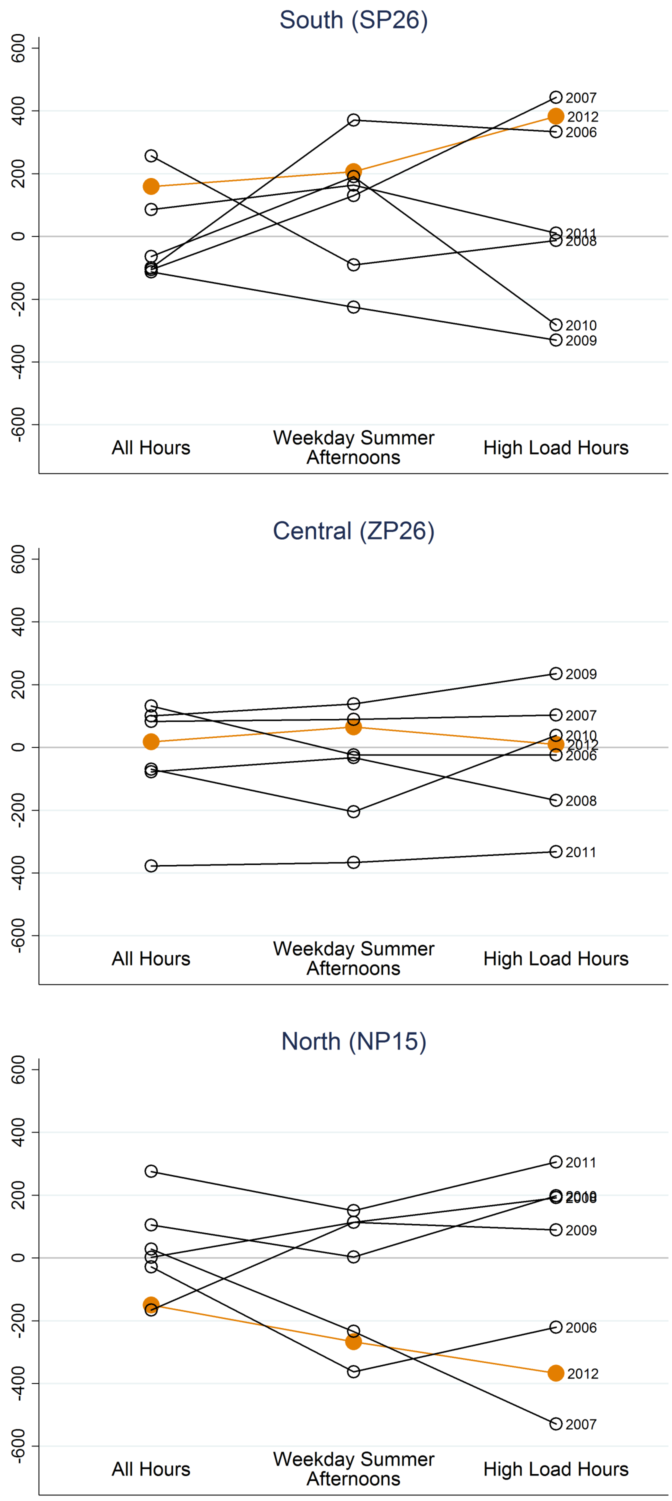
Note: Demand is for the mean level in a given week for the three regions. The vertical line shows the week the second SONGS unit went down (February 2012). PGE is roughly the Northern half of the state, SDGE is the Southern half excluding the San Diego area, and SDGE is the San Diego area.

Appendix Figure A3: Regional Load and Price Differentials



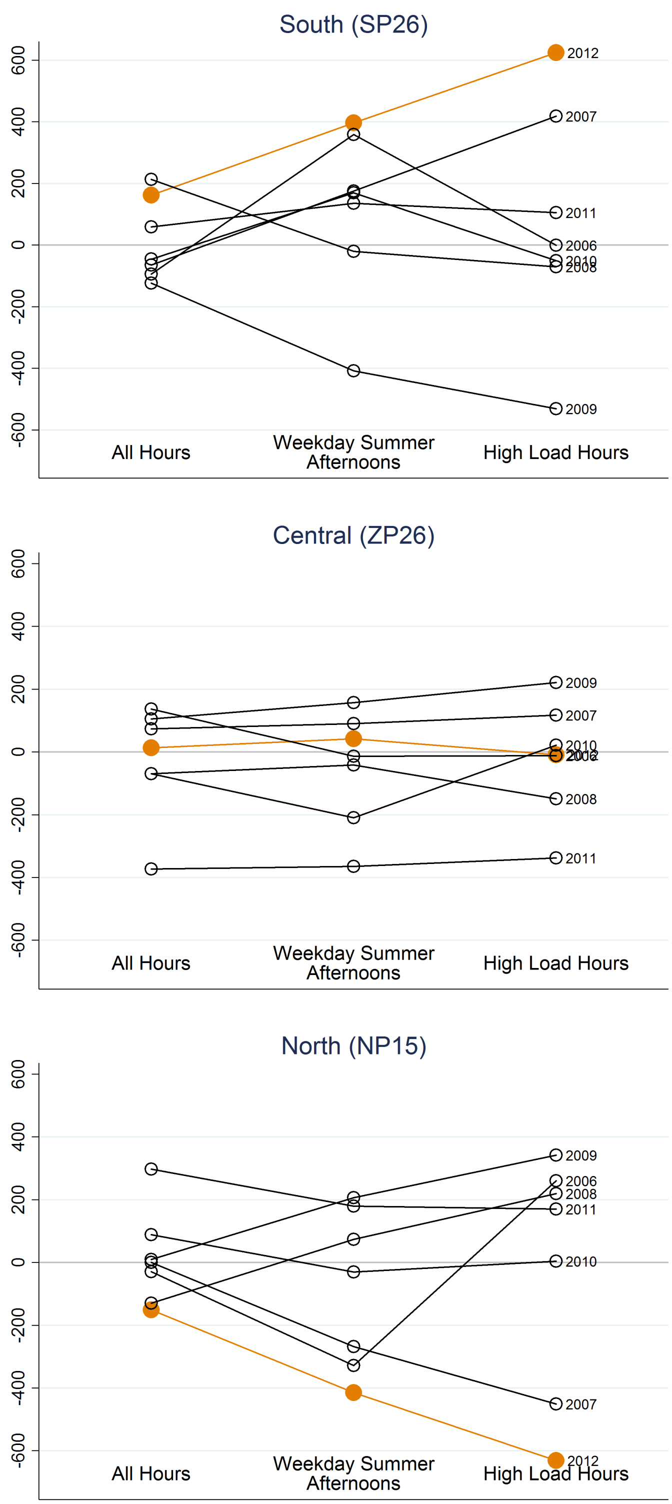
Note: This figure describes daily demand and price differentials at 3 pm between January 2009 and September 2013. Weekends are excluded. The vertical line shows the day the second SONGS unit went down (February 1, 2012).

Appendix Figure A4: Out-of-Order Changes, by Year



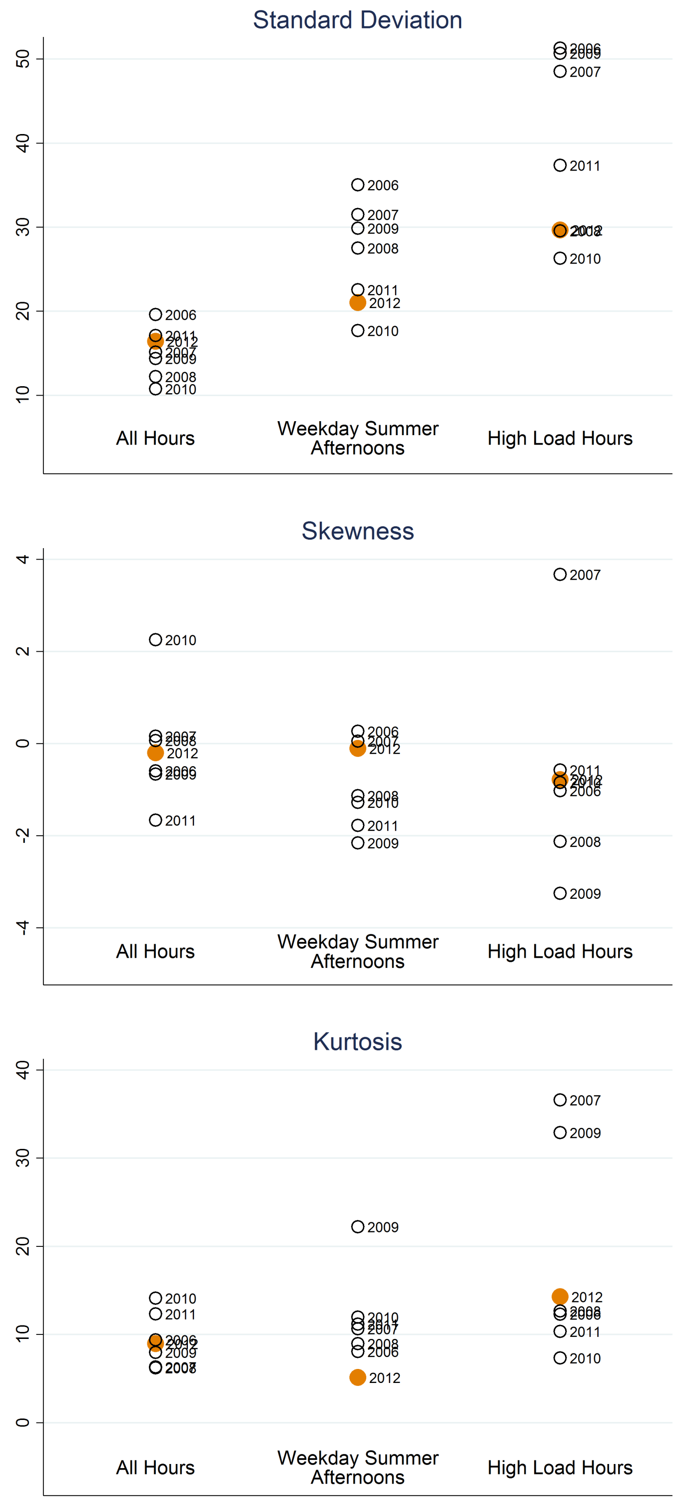
Note: These figure show out-of-order estimates for the main sample of interest (2012, in orange) compared to other years for which we have data (hollow black circles).

Appendix Figure A5: Out-of-Order Changes, without AES, by Year



Note: These figure show out-of-order estimates, excluding AES-owned plants, for the main sample of interest (2012, in orange) compared to other years for which we have data (hollow black circles).

Appendix Figure A6: Unit-Level Diagnostics, by Year



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

Appendix Table A1: 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 A2: Most Affected Plants, Weekday Summer Afternoons

Rank	Plant Name	Owner	Plant Type	Zone	Marginal Cost ($ per MWh)	Capacity (Megawatts)	Merit-Order Change (MWhs)	Out-of-Order Change (MWhs)
			Panel A. Merit-Order Increases, Top Five					
1	Moss Landing	Dynegy	Comb Cyc / Boiler	NP15	26/26/27/27/36/37	2541	236	43
2	AES Alamitos	AES	Boiler	SP15	40/41/41/43/45/46	1934	181	-213
3	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	25/25/25/26	1066	152	125
4	Cabrillo I Encina	NRG	Boiler	SP15	40/40/41/43/44	954	89	118
5	AES Redondo	AES	Boiler	SP15	40/43/54/63	1348	88	-67
			Panel B. Out-of-Order Increases, Top Five					
1	Coolwater	NRG	Comb Cyc / Boiler	SP15	35/37/37/38/40/42	636	30	158
2	La Paloma	La Paloma Gen Co, LLC	Comb Cyc	ZP26	25/25/25/26	1066	152	125
3	Cabrillo I Encina	NRG	Boiler	SP15	40/40/41/43/44	954	89	118
4	Otay Mesa	Calpine	Comb Cyc	SP15	25/26	596	54	98
5	Elk Hills	Occidental Petroleum	Comb Cyc	ZP26	26/26	548	11	86
			Panel C. Out-of-Order Decreases, Top Five					
1	AES Alamitos	AES	Boiler	SP15	40/41/41/43/45/46	1934	181	-213
2	Panoche	Energy Investors Fund	Combust Turbine	NP15	34/35/35/35	412	54	-105
3	Calpine Sutter	Calpine	Comb Cyc	NP15	24/25	564	60	-94
4	Los Esteros Critical	Calpine	Combust Turbine	NP15	37/37/37/37	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. 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 A3: Including 2013

	Average Hourly Change, By Region		
	Southern California (SP26)	Central California (ZP26)	Northern California (NP15)
	(1)	(2)	(3)
	Panel A: All Hours		
Merit-Order Change in Net Generation (MWh)	883	301	950
	(19)	(17)	(18)
Out-of-Order Change in Net Generation (MWh)	63	40	-78
	(77)	(70)	(75)
	Panel B: Weekday Summer Afternoons		
Merit-Order Change in Net Generation (MWh)	1037	278	853
	(43)	(15)	(35)
Out-of-Order Change in Net Generation (MWh)	191	22	-193
	(126)	(77)	(107)
	Panel C: High Load Hours		
Merit-Order Change in Net Generation (MWh)	1214	183	748
	(41)	(29)	(36)
Out-of-Order 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.