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ATTACHMENT A

Aliso Canyon I.17-02-002 Phase 2: Results of Econometric Modeling

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION
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Executive Summary

Pursuant to Senate Bill (SB) 380, the California Public Utilities Commission's (CPUC) Energy Division staff (staff) performed three economic studies to estimate the quantifiable impacts of eliminating or minimizing use of the Aliso Canyon natural gas storage facility on core and noncore natural gas customers. Since the use of Aliso Canyon has been reduced in the years following the 2015-2016 leak, these studies use data from after the leak to represent minimizing the use of that facility. The three studies analyze 1) natural gas price volatility, 2) the impact of natural gas storage availability on ratepayers' bills and 3) the impact of natural gas price increases on implied market heat rate and excess electricity costs. This report summarizes the data collected, the study methods, and the resultant findings.

These economic analyses are complicated by the rupture of Line 235-2 on October 1, 2017, and its subsequent removal from service for the remainder of the study period. This pipeline outage eliminated a second piece of critical infrastructure from the SoCalGas system and made it very difficult to make clear-cut determinations regarding the economic impact of the Aliso limitations. Because each of these pieces of infrastructure has the capacity to substitute for some of the functions of the other—for example, Aliso Canyon could have replaced much of the lost capacity on Line 235-2 if it had been in normal use—the combined impacts of their outages are not simply additive. Nonetheless, staff have made every effort to tease out the economic impacts from each of these events in the three studies described below.

The first study, referred to as the Volatility Analysis, assesses the volatility of natural gas prices at SoCal Citygate. Staff evaluated the frequency and magnitude of gas price increases since the Aliso Canyon leak to quantify the level of financial risk ratepayers could face due to gas price volatility. This analysis finds that SoCal Citygate and SoCal Border prices became more volatile in 2017 and even more so in 2018. By 2018, increases of 25 percent in the same-day gas price became common. Additionally, the risk of potential losses for natural gas buyers from SoCal Citygate and SoCal Border hubs increased in 2017 and even more so in 2018. In 2018, the Value at Risk is over 35 percent and the Conditional Value at Risk is over 85 percent.

The second study, referred to as the Difference in Differences (DID) study, estimates the economic impact of Aliso Canyon limitations on core customers by analyzing core customer billing data for Southern California Gas Company (SoCalGas) and Pacific Gas & Electric (PG&E) customers in zip codes where SoCalGas and PG&E service areas overlap. Staff found that after the Aliso Canyon incident, the average monthly gas procurement cost from 2016 through 2018 increased by $1.82/bill. To separate the economic impact of Aliso Canyon limitations on core customers in each year after the Aliso Canyon incident, and to attempt to isolate the impact of pipeline outages that began in October 2017, the study estimated the impact in 2016, 2017 and 2018. In 2016, the average gas procurement cost increased by $1.32/bill compared to 2013-2015 (the time period before the Aliso Canyon incident). In 2017, the average gas procurement cost increased by $1.89/bill compared to 2013-2015; this likely includes the full effect of the Aliso Canyon limitations and the partial effect of major transmission pipeline outages beginning on October 1, 2017. In 2018, the average gas procurement cost increased by $2.25/bill compared to 2013-2015; this likely includes the full effect of the Aliso Canyon limitations and the full effect of the pipeline outages. Using the 2016 monthly bill impact as an estimate, the total impact of the loss of Aliso Canyon on core residential customers is roughly $102 million per year.

Lastly, the third study, referred to as the Implied Market Heat Rate (IMHR) and Excess Electricity Costs study, assesses California's electric market efficiency before and after the Aliso Canyon incident and estimates excess electricity costs caused by the Aliso Canyon limitation. This study found IMHR to be higher in NP15 (northern area within CAISO electricity market) compared with SP15 (southern area within CAISO electricity market), most notably after outages on Lines 4000 and 235-2 in October 2017. There were also significant increases in IMHR in NP15 compared to SP15 in 2018 even with the decrease in electric demand and overall generation in that year. Staff concluded that increased IMHR in 2018 can be explained by the volatility and higher price of natural gas at SoCal Citygate, related to the combined impact of pipeline outages and limitations on Aliso Canyon, and not one or the other of these conditions in isolation.

The IMHR and Excess Electricity Costs study also found that electricity costs in SP15 began to increase in October 2017, concurrent with the outage of Line 235-2. Staff estimated that electric customers paid about $599 million in excess costs in 2018 due to pipeline outages and the Aliso restrictions. This estimate does not include other electricity costs such as administration costs or purchases of imported electricity, so it is likely an underestimate.

Background

SoCalGas's Aliso Canyon natural gas storage facility, located in the Santa Susana Mountains of Los Angeles County, is the largest natural gas storage facility in California. A major gas leak was discovered at Aliso Canyon on October 23, 2015. On January 6, 2016, the governor ordered SoCalGas to maximize withdrawals from Aliso Canyon to reduce the pressure in the facility.[1] The CPUC subsequently required SoCalGas to leave 15 billion cubic feet (Bcf) of working gas in the facility that could be withdrawn to maintain reliability. On May 10, 2016, Senate Bill (SB) 380[2] was approved. Among other things, the bill:

1. Prohibited injection into Aliso Canyon until a safety review was completed and certified by the Division of Oil, Gas, and Geothermal Resources (DOGGR)[3] with concurrence from the CPUC;
2. Required DOGGR to set the maximum and minimum reservoir pressure;

[1] https://www.gov.ca.gov/2016/01/06/news19263/
[2] Statues of 2016, chapter 14.
[3] DOGGR has since been renamed. It is now the California Geologic Energy Management Division or CalGEM.

3. Charged the CPUC with determining the range of working gas necessary to ensure safety and reliability and just and reasonable rates in the short term; and
4. Required the CPUC to open a proceeding to determine the feasibility of minimizing or eliminating use of Aliso over the long term while still maintaining energy and electric reliability for the region.

On February 9, 2017, pursuant to Senate Bill 380, the CPUC opened Investigation (I.) 17-02-002 to determine the long-term feasibility of minimizing or eliminating the use of the facility while still maintaining energy and electric reliability for the Los Angeles region at just and reasonable rates. Since initiation of I.17-02-002, the CPUC has engaged in an extensive stakeholder process to develop models (including assumptions, scenarios and inputs) to evaluate the effects of minimizing or eliminating the use of Aliso Canyon, culminating in an Assigned Commissioner and Administrative Law Judge's (ALJ's) Ruling Adopting Scenarios Framework and Closing Phase 1 of I.17-02-002, issued on January 4, 2019.[4] The adopted Scenarios Framework set forth the roadmap for three modeling streams to be completed in Phase 2 of the investigation—hydraulic modeling, production cost modeling, and economic modeling. Staff presented production cost modeling results in a workshop on July 28, along with the 1 in 10 hydraulic modeling results. Staff will present final 1 in 35 hydraulic modeling results as well as sensitivity analysis at a workshop on October 15. Together this analysis will present a picture of the effects of the Aliso limitations imposed since 2017 and important reliability considerations regarding maintenance of the Aliso Canyon storage field.

The Scenarios Framework outlined three econometric studies to be performed by CPUC staff, the results of which are presented in this report.

Introduction

In addition to improving SoCalGas' system reliability, natural gas storage fields can be used to reduce the economic impact of volatility in natural gas prices. Gas can be purchased and stored in the off-season, when prices are generally lower, for use in the summer and winter, when demand and prices tend to be higher. Storage also helps moderate costs during temporary price spikes, which typically occur during hot or cold weather events.

Loss of storage impacts core and noncore customers differently. SoCalGas purchases both gas and storage rights for core customers while noncore customers buy their own gas and have historically had the option to pay for storage rights. Since gas is a pass-through cost for core customers, the price paid by the utility is passed on to residential and small business consumers without a mark-up. Loss of storage could increase core customers' exposure to spot market volatility due to increased reliance on spot purchases as opposed to withdrawals from storage. Noncore customers have been

[4] The (I.)17-02-002 Scenarios Framework can be found here: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M258/K116/258116686.PDF.

unable to purchase new storage rights in the primary storage market since restrictions on the use of Aliso Canyon were put in place, leaving them more exposed to both market volatility and financial penalties for being out of balance.[5]

Since the leak began on October 23, 2015, the CPUC, with input from the California Energy Commission (CEC), the California Independent System Operator (CAISO), and the Los Angeles Department of Water and Power (LADWP), has made several determinations to limit the storage field's maximum allowable inventory and the conditions under which gas withdrawals may occur. It is important to note that these limitations changed at various points during the period analyzed in this report: 2016-2018. Aliso Canyon was capped at 15 Bcf with no injection allowed from January 2016 until July 19, 2017, when CalGEM and the CPUC certified that the field was safe for an inventory of up to 68.6 Bcf. In accordance with SB 380's directive to minimize the inventory at Aliso Canyon while still ensuring reliability and reasonable rates, the CPUC set a lower maximum inventory that has been modified over the years due to changing conditions and information. It has increased from 23.6 Bcf in July 2017 to 24.6 Bcf in December 2017 to 34 Bcf in July 2018. The Aliso Canyon Withdrawal Protocol (Withdrawal Protocol) further restricts usage of the field. From November 2, 2017, through July 22, 2019, the then-current Withdrawal Protocol classified the field as an asset of last resort, which meant that it could only be used when reliability was threatened and after SoCalGas had asked CAISO and LADWP to voluntarily curtail electric generation. On July 23, 2020—after the period examined in this report—the CPUC modified the Withdrawal Protocol, removing the asset of last resort language and allowing the field to be used during an emergency and under limited circumstances to avoid gas price spikes and overly depleting the non-Aliso fields.[6]

In addition to the Aliso Canyon inventory limits and usage restrictions, the SoCalGas system was operating with outages and pressure reductions on important transmission pipelines. Line 235-2, a major gas transmission pipeline which imports gas into the SoCalGas system from interstate pipelines at the California and Arizona border, ruptured on October 1, 2017. The rupture led to safety concerns about nearby Line 4000, which was also taken out of service. Together, the loss of the two major transmission pipelines resulted in an 800 MMcfd reduction in total SoCalGas system pipeline capacity. These outages were in addition to an existing outage on Line 3000 and a 200 MMcfd reduction in capacity on Line 2000. Gas supplies to the greater Los Angeles area were drastically reduced. Line 4000 returned to service at reduced capacity on December 22, 2017, increasing system receipt capacity in the Northern Zone to 870 MMcfd. Line 235-2 returned to

[5] The SoCalGas System Operator is responsible for maintaining the system's balance, but it does not control most gas procurement. To maintain balance on the system, the SoCalGas System Operator calls low Operational Flow Orders (OFOs) when gas deliveries are too low and high OFOs when deliveries are too high. When an OFO is called, customers are required to balance supply and demand within a specified tolerance band; otherwise, they face specified financial penalties for noncompliance.
[6] The Aliso Canyon Withdrawal Protocol can be found here: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-Revised-April12020clean.pdf

service at reduced capacity on October 14, 2019. The return of Line 235-2 increased system receipt capacity in the Northern Zone to 990 MMcfd

In this report, staff provides a review of the economic impacts of those limitations. The report is divided into one section per study:

1. **Volatility Analysis** – Evaluates the frequency and volatility of gas price increases and quantifies the level of the financial risk customers face due to gas price volatility.
2. **The Impact of Natural Gas Storage on Ratepayers' Bills** – Estimates the economic impact of Aliso Canyon limitations on core customers.
3. **The Implied Market Heat Rate and Excess Electricity Costs Analyses –** Assesses market efficiency before and after the Aliso Canyon incident and estimates excess electricity costs caused by the Aliso Canyon limitations.

Each section contains the data inputs, methodologies, and the results of the statistical and econometric models utilized.

1 Volatility Analysis

The Volatility Analysis assesses the amount of volatility in SoCal Citygate prices. Volatility could be due to weather, lack of storage, outages or other factors over time. The analysis examines SoCal Citygate prices before and after the capacity reduction at Aliso Canyon in 2016 to test whether limitations on Aliso Canyon usage are a significant factor in explaining gas price volatility.

1.1 Data Sources

The table below shows the variables and data sources for the volatility analysis. Staff used four years of data (2015-2018) for four markets (SoCal Citygate, PG&E Citygate, SoCal Border and Henry Hub). Staff used 2015 data to capture one year before the Aliso Canyon event, and staff used that data to compare with the three following years. Staff also compared local prices to a control price—Henry Hub—which was likely to be unaffected by the Aliso Canyon event.

Variable	**Data Source**
SoCal Citygate, PG&E Citygate, SoCal Border and Henry Hub daily gas prices	Natural Gas Intelligence (NGI)

Note: NGI's Daily Gas Price Index reports Cycle 1 prices.

1.2 Methodology

Staff used R Suite to conduct a volatility analysis of SoCal Citygate natural gas commodity prices using two approaches. The first approach evaluated the frequency and volatility of gas price increases. The second approach, referred to as Value at Risk (VaR) and Conditional Value at Risk (CVaR) approach, quantified the level of financial risk the customer was expected to face due to gas price volatility.

1.1.1 Frequency and Volatility of Gas Price Increases

Staff calculated same-day index price increases and next-day index price increases to quantify the frequency and volatility of gas price increases.

1.1.1.1 Same-Day Index Price Increase

Staff calculated the magnitude of increases in the same-day natural gas prices using the following formula:

Difference = *maxp(t) - p(t)*

Where:
maxp(t) is the highest price for that day. ***p(t)*** is the average price for that day.

Staff calculated the frequency in which same-day price increases occurred. The frequency analysis consists of three tranches of same-day gas price data: increases of 10 percent or less, increases between 10 and 25 percent, and increases exceeding 25 percent.

1.1.1.2 Next-Day Index Price Increase

Staff calculated the magnitude of increases in the next-day natural gas prices using the following formula:

Volatility = 1 - *(p(t)/p(t-1))*

Where:
p(t) is the average price for today
p(t-1) is the average price for yesterday

Staff used four years of data (2015-2018) for four markets (SoCal Citygate, PG&E Citygate, SoCal Border and Henry Hub). Then, staff calculated the frequency in which next-day price volatility occurred. The frequency analysis here also consists of three tranches of next-day gas price data: increases of 10 percent or less, increases between 10 and 25 percent, and increases exceeding 25 percent.

1.1.2 VaR and CVaR

Risk Management embodies the process and the tools used for evaluating, measuring and managing the various risks of commodities and other assets. The value of natural gas can change over time as market conditions change. A price forecast is the foundation for determining risk in managing the natural gas supply. In the gas market, producers and providers execute trading contracts based on a price forecast to help match supply with demand. Natural gas market participants buy or sell contracts on the open market to meet contracted deliveries when forecasted demand exceeds contracted supply, sell excess capacity when demand is less than supply, or speculate to increase earnings through futures contracts. A risk management strategy that quantifies and manages risk can allow market participants to avoid unexpected losses due to price fluctuations, reduce volatility while maximizing the return on natural gas investment, or in some cases meet regulatory requirements that limit exposure to risk.

An unpredictable, volatile and risky market environment has become common in SoCalGas service territory due to the Aliso Canyon limitation. In particular, natural gas buyers have been exposed to uncertain and highly volatile gas prices. The gas price for the next day, month or year has become an unpredictable and risky investment. To quantify these risks, staff used VaR and CVaR.

Staff calculated the VaR and the CVaR using a historical simulation approach. In this approach, the VaR is directly calculated from past returns. VaR is a measure of the risk of losing money on investments. It estimates how much an investment might lose within a given range of probability in a time period such as a day, month or year. The CVaR is equal to the average of all expected losses that are greater than or equal to VaR.

1.1.2.1 VaR

Staff used the historical method to calculate the VaR. Staff calculated how much a customer could lose relative to expected gas price forecasts due to daily change in the gas price (often called the historical return) over a one-year horizon using the following formula:

$$r(t, t-1) = \ln (p(t)/p(t-1))$$

Where:
r(t, t-1) is the daily change in the gas price for customers
ln (p(t)/p(t-1)) is the natural logarithm of one day's price divided by the day before's price

Staff used five years of data (2014-2018) for four markets (SoCal Citygate, PG&E Citygate, SoCal Border and Henry Hub). An advantage of the historical method is that the approach is assumption free and does not require a normal distribution. In other words, there are no assumption that the data is normally distributed around the mean. Next, staff ranked expected costs caused by gas price increases from worst to best. Finally, staff attempted to calculate the VaR equal to or exceeding 95 percent of possible excess costs that customers paid from gas price increases on the same day or the next day.[7] In other words, there is a 5 percent chance that customers pay excess costs greater than or equal to VaR.

1.1.2.2 CVaR

CVaR, also known as the average expected loss, is the average loss expected if the worst-case threshold is exceeded. CVaR is dependent on VaR values computed in the previous exercise. It is the average of all expected losses that are greater than or equal to the risk threshold chosen for VaR. The following formula is used to calculate CVaR:

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[7] 95 percent probability is a common industry standard for estimating VaR.

$$CVaR = \frac{1}{1-c}\int_{-1}^{VaR} xp(x)\,dx$$

Where:

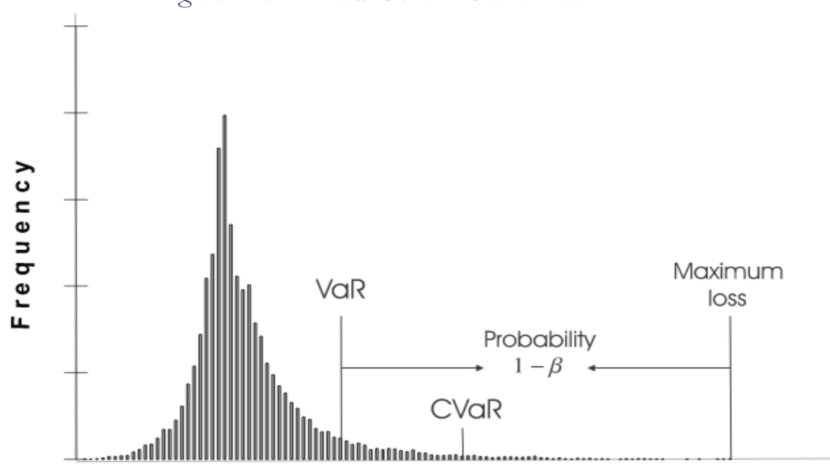
p(x)dx is the probability that the next change in the gas price for customers will fall between a certain price level x and a change to that price level x + dx.

c is the percentage level on the distribution that provides a desired risk tolerance level to calculate VaR

VaR is the expected excess costs related to gas price increases at the risk tolerance threshold VaR level

Figure 1 illustrates the process of calculating the VaR and CVaR. In this calculation the probability 1- β is equal to 5 percent. (100 percent-95 percent).

Figure 1: VaR and CVaR Calculation



1.3 Results

Staff evaluated the frequency and magnitude of gas price increases since the Aliso Canyon leak to quantify the level of financial risk ratepayers could face due to gas price volatility. This analysis finds that SoCal Citygate and SoCal Border prices became more volatile in 2017 and even more so in 2018. By 2018, increases of 25 percent in the same-day gas price became common. Additionally, the risk of potential losses for natural gas buyers from SoCal Citygate and SoCal Border hubs increased in 2017 and even more so in 2018. In 2018, the VaR is over 35 percent and the CVaR is over 85 percent.

1.1.3 Volatility Measured by Frequency and Magnitude of Gas Price Increases

1.1.3.1 Same Day Index Price Increase

Figure 2 represents the frequency of same-day index price increases on weekdays. Price increases on weekends are not available from the NGI dataset. There was a small increase in volatility in SoCal Border and Citygate prices in 2016 but significant increases in volatility in 2017 and 2018 after pipeline outages added to the effect of the Aliso event. Price increases below 10% for SoCal Border and SoCal CityGate were very common in the majority of days in 2016, but that trend changed in subsequent years. The frequency of price increases at SoCal Border and SoCal CityGate between 10 percent and 25 percent and greater than 25 percent almost tripled between 2017 and 2018. Increases of 10 percent or less went from about 75 percent of the days in 2017 to less than one third of the days in 2018.

Figure 2: Same-Day Volatility Count for Weekdays

1.1.3.2 Next-Day Index Price Increase

Figure 3 represents the frequency of next-day index price increases for weekdays. There were price increases in only about half the days of the year, and days without price increases are not included. That is why Figure 3 and Figure 4 include fewer data points than Figure 2. There is a small increase in volatility in SoCal Border and City Gate prices in 2016, and about 50 percent increase in days with volatility of over 10 percent in 2017 after pipeline outages add to the effect of the Aliso event. There is a similar pattern in next-day price increases as the same day price increases, where gas price increases between 10 percent and 25 percent increased from less than a third in 2017 to nearly half the weekdays during summer in 2018. By 2018, there was a threefold increase in next-day gas price increases between 10 percent and 25 percent and over 25 percent.

Figure 3: Next-Day Volatility Count for Weekdays

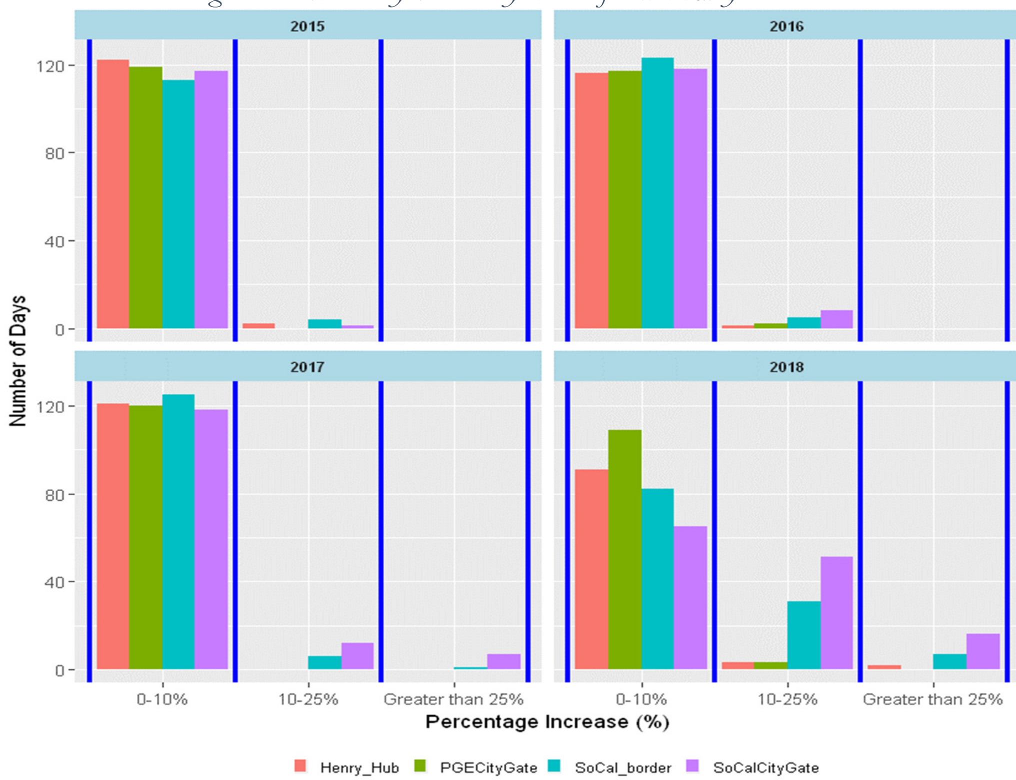
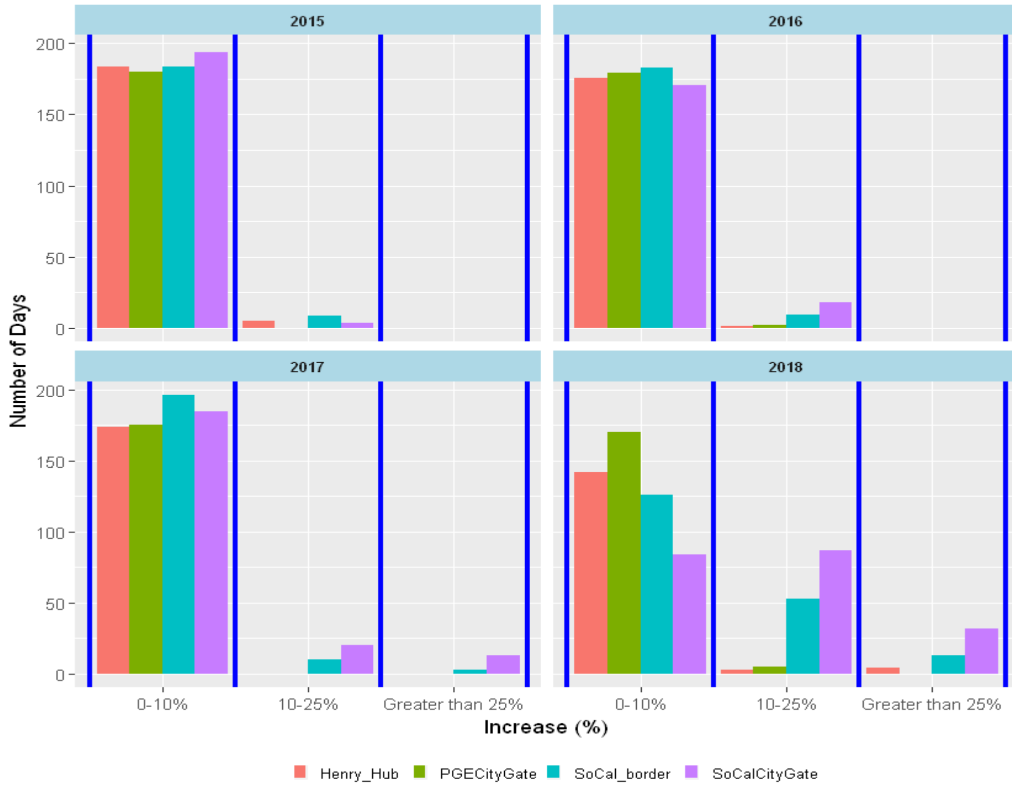


Figure 4 represents the frequency of next-day index price increases on all days of the week, including weekends. Similar to Figure 3: Next-Day Volatility Count for Weekdays, there was a small increase in volatility in SoCal Border and City Gate prices in 2016 but significant increases in volatility in 2017 and 2018 after pipeline outages add to the effect of the Aliso event. In 2018, the next-day gas price increases of 10 percent or more became more common.

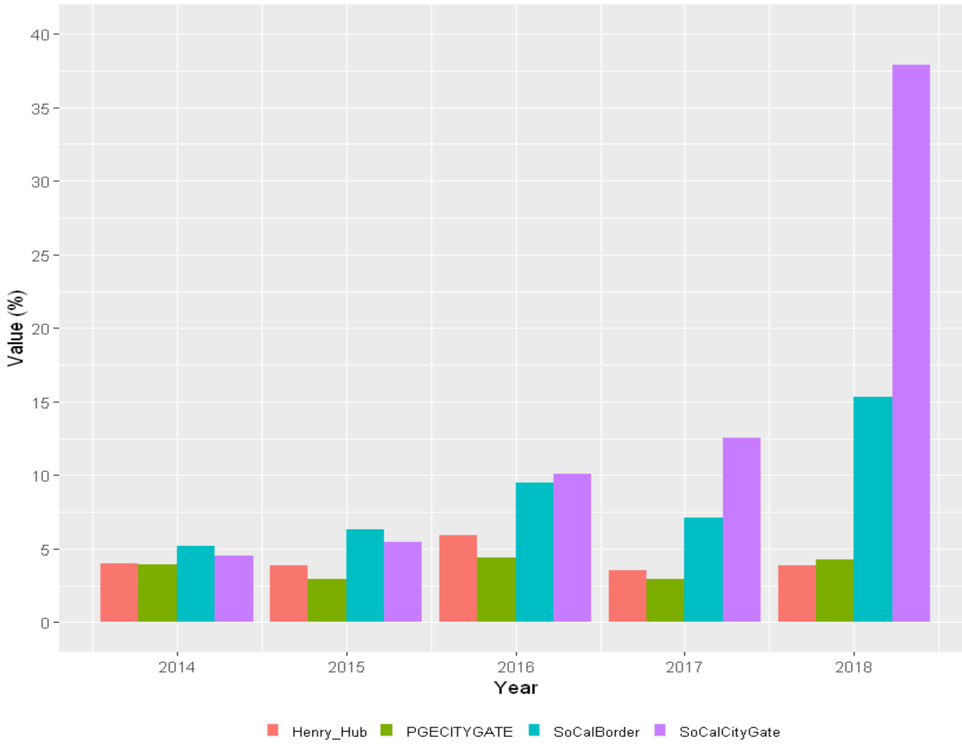
Figure 4: Volatility Count for all days including Weekend



1.1.3.3 VaR

Figure 5 represents the VaR at 95 percent probability. Potential VaR for natural gas buyers from SoCal Citygate and Border hubs increased in 2017 and more so in 2018, shown by the blue and purple bars that grow in 2017 and 2018. In 2018, the VaR is over 35 percent meaning that there is a 5 percent chance that customers can expect a daily loss (due to gas price increases) of 35 percent or more.

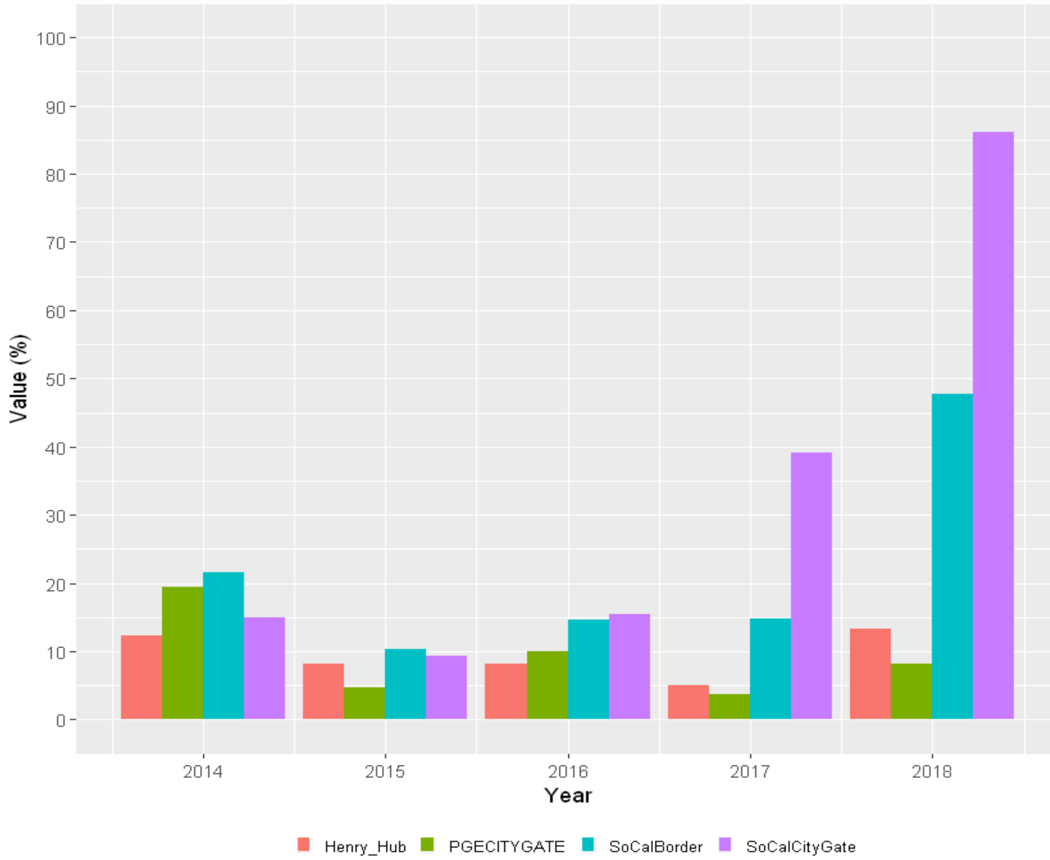
Figure 5: Value at Risk (VaR)



1.1.3.4 CVaR

Figure 6 represents the CVaR, illustrating that the risk and potential loss for natural gas buyers from SoCal Citygate and SoCal Border hubs increased in 2017 and more so in 2018 shown by the blue and purple bars that grow while CVaR at the other hubs remain the same. By 2018, gas prices at SoCal Citygate has become so volatile that CVaR at 95 percent confidence was 85 percent. At the most extreme, there was a 5 percent chance that customers could expect increased gas costs equal to 85 percent of the amount they would usually spend on gas.

Figure 6: Conditional Value at Risk (CVaR)



1.2 Summary of the Key Results of Volatility Analysis

- SoCal Citygate and Border prices became somewhat more volatile in 2016 and significantly more volatile in 2017 and 2018.
- Same-day price increases of 10 percent or less became less frequent from 2017 to 2018, decreasing from about 75 percent of the days in 2017 to less than one third of the days in 2018.
- There is a similar pattern in next-day price increases, where gas price increases between 10 percent and 25 percent increased from less than a third in 2017 to nearly half of the weekdays of the summer in 2018. By 2018, there was a threefold increase in next-day gas price increases between 10 percent and 25 percent and increases over 25 percent.
- In 2018 the VaR was over 35 percent meaning that there was a 0.05 probability that customers could expect a daily loss of 35 percent or more.
- By 2018, gas prices at SoCal CityGate had become so volatile that CVaR at 95 percent confidence was over 85 percent, translating to the 0.05 probability that gas customers could face daily gas price increases (or loss on gas investment) totaling 85 percent of the amount paid for gas .

2 Difference in Differences Analysis Results - Impact of Natural Gas Storage on Gas Commodity Costs

The analysis in this section quantifies the impact of natural gas storage on gas commodity costs. More specifically, the analysis quantifies the impact of Aliso Canyon storage availability on the gas commodity charge portion of core customers' bills. An econometrics technique known as "Difference in Differences" (DID)[8] was used to estimate the economic impact of Aliso Canyon limitations on core customers. In this case, the control group is the group of PG&E customers in zip codes where SoCalGas and PG&E service areas overlap because the PG&E customers were not impacted by the Aliso Canyon limitations (the intervention). The SoCalGas customers experienced the impact of the Aliso Canyon limitations, making them the treatment group. The DID analysis described in this section is not a gas or electric system reliability assessment.

2.1 Data Sources:

The table below shows the variables and data sources for the DID analysis:

Variable	Data Source
Monthly commodity procurement costs taken from core gas customers billing data	Data Request from SoCalGas
Monthly commodity procurement costs taken from core gas customers billing data	Data Request from PG&E

2.2 Methodology

The DID technique is beneficial in instances when it is not possible to create a randomized experiment to assess the impact of an intervention or change. In the DID model, outcomes are observed for two groups during two time periods. After an intervention occurs, such as the Aliso Canyon limitations, two time periods can be identified, and control and treatment groups are naturally created. For this analysis, staff used R Suite to perform the DID analysis.

To estimate DID, staff used a robust standard error method to address heteroscedasticity. Heteroskedasticity means data has a different dispersion or variability across the range of data. In regression analysis it is assumed that data has equal variability (homoscedasticity) but if this is not true, it is hard to test for significance of results. For that reason, the regular standard error method is no longer valid, and the robust standard error method was needed. The use of robust standard errors is a technique to obtain unbiased standard errors of regression coefficients under heteroskedasticity and serial correlation.

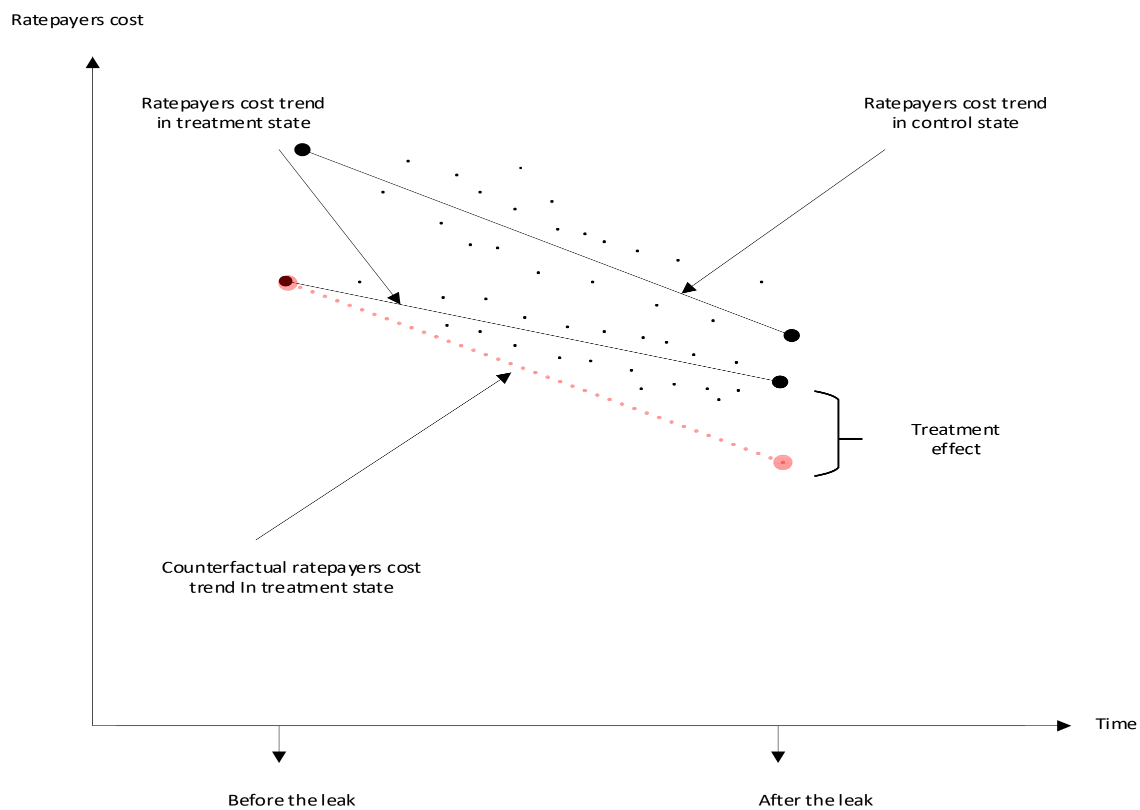
In this analysis, SoCalGas customers are the treatment group and PG&E customers in the same zip code are the control group. The two time periods are defined as the periods before and after the

[8] For more information on Difference in Differences: http://www.nber.org/WNE/Slides7-31-07/slides_10_diffindiffs.pdf

Aliso Canyon leak. Only SoCalGas customers were impacted by the Aliso Canyon limitations, as the Aliso Canyon gas storage facility does not serve the PG&E service territory or customers. Therefore, the PG&E customer control group was not exposed to the Aliso Canyon limitation impacts during either period.

The DID approach can be applied to repeated cross-sections of a group or to panel data over a certain time. The key assumption in DID is the parallel trend assumption, which states that the average outcome for the treated and control groups would have moved in parallel if the Aliso Canyon limitations had not occurred. Figure 7 illustrates a basic concept of the DID technique. The hypothesis is that the control group and the treatment group would follow the same commodity cost trajectory with respect to the time before and after the Aliso Canyon limitations.

Figure 7: Basic Concept of DID



Staff used the gas commodity procurement data from customers' bills in zip codes where the SoCalGas and PG&E service territories overlap because these households have similar geography, demographics, and weather patterns. SoCalGas and PG&E service areas overlap (as shown on Figure 8) in the towns of Arvin, Bakersfield, Fellows, Fresno, Del Ray, Fowler, Paso Robles, Selma, Taft, Tehachapi, and Templeton. Figure 9 demonstrates the parallel trend assumption in gas commodity procurement cost on an annual basis, and Figure 10 illustrates monthly parallel trends in actual gas commodity procurement costs starting in 2013 until trends began to become less parallel in 2017.

Figure 8: Map of Overlapping SoCalGas and PG&E Zip Codes

Figure 9: Parallel Trend Validation of Annual Average Gas Commodity Procurement Costs ($)

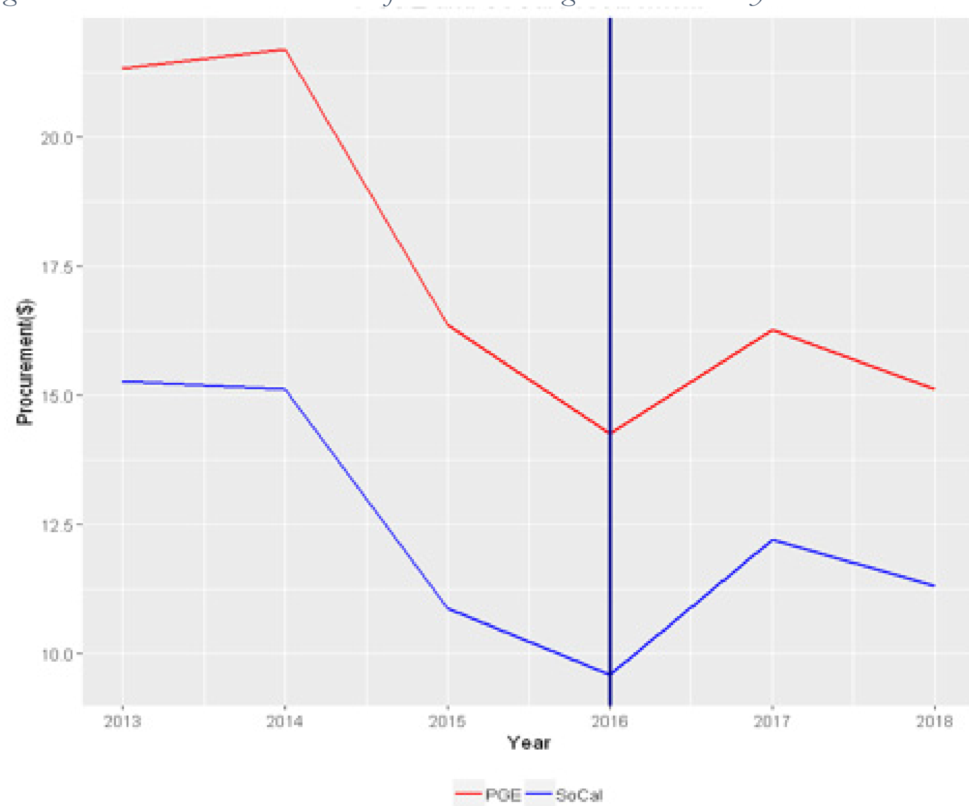
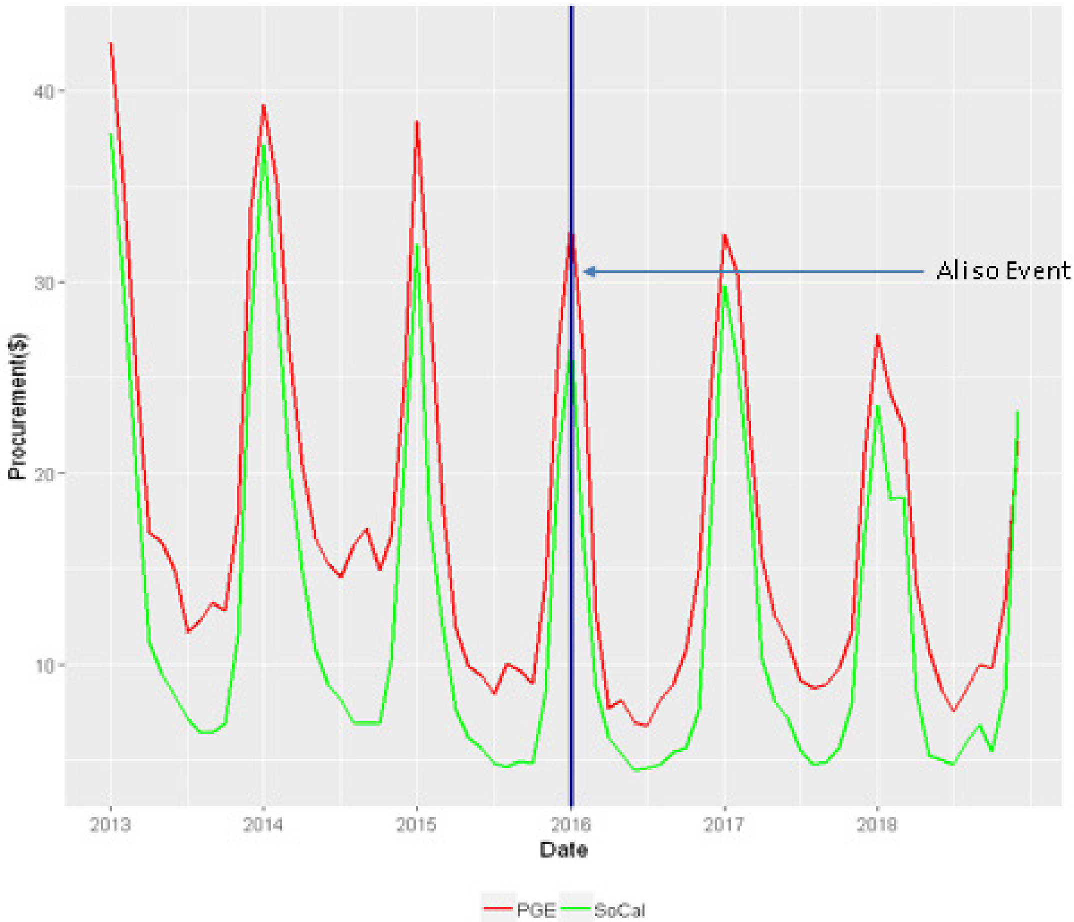


Figure 10: Parallel Trend Validation of Monthly Data



Staff compared the commodity cost data from SoCalGas customers, the treatment group, and PG&E customers, the control group, before and after the Aliso Canyon leak. The change in outcomes that are related to the Aliso Canyon incident can then be estimated from the DID analysis as follows:

(B2−B1) − (A2−A1)

Where:
B1 and B2 represent gas commodity procurement costs for SoCalGas customers before and after the Aliso Canyon limitations respectively, and (B2−B1) represents the difference in commodity procurement costs in customer monthly bills after vs. before the Aliso Canyon limitations for the SoCalGas customers.

A1 and A2 represent gas commodity procurement costs for PG&E customers before and after the Aliso Canyon limitations respectively and (A2−A1) represents the difference in commodity procurement costs in customer monthly bills after vs. before the Aliso Canyon limitations for the PG&E customers. If the DID estimate is not statistically significant[9] then the hypothesis that the Aliso Canyon limitations had no impact on gas commodity procurement costs cannot be rejected. On the other hand, if the DID estimate is statistically significant, then the hypothesis that the Aliso Canyon limitations had no impact on SoCalGas' gas commodity procurement costs is rejected and staff accepts that Aliso Canyon limitations has an impact on SoCalGas' gas commodity procurement costs.

The DID estimates are derived from a regression model:
$$Yst = \beta 0 + \beta 1Ts + \beta 2PTt + \beta 3(Ts \times PTt) + \varepsilon st$$

Where:
Yst is the observed outcome in group **'s'** and period **'t'**. In this case, it is the natural gas procurement commodity cost component of an individual ratepayer's monthly gas bill.
Ts is a dummy variable set to 1 if the observation is from the "treatment" group in either time period.
PTt is a dummy variable set to 1 if the observation is from the post-treatment period for either group.
εst is an error term, ***β0*** is the intercept, ***β1*** is the coefficient of the *Ts* and ***β2*** is the coefficient of *PTt*. ***β3*** is the coefficient of the treatment effect, which is the coefficient of interest. The estimate of *β3* is identical to the double difference: (B2−B1) − (A2−A1).

To separate the economic impact of the Aliso Canyon limitations and the pipeline outages, staff compared the gas commodity procurement costs of SoCalGas and PG&E core customers before and after the Aliso Canyon leak. Staff estimated four DID regressions comparing gas commodity procurement costs for the years 2013-2015 (representing the period before the Aliso Canyon leak) to four time periods after the Aliso Canyon leak.

The four post-Aliso Canyon leak time periods are:
1. 2016-2018, to represent the period after the Aliso Canyon incident;
2. 2016, to represent the period after the Aliso Canyon incident and before the pipeline outages;
3. 2017, to represent the period after the Aliso Canyon incident and three months after the pipeline outages; and
4. 2018, to represent the period after the Aliso Canyon incident and the full impact of pipeline outages.

[9] Statistically significant means that if the Null Hypothesis is true there is a low probability of getting a result that large or larger.

2.3 Results

The regression results are provided in Figures 11-14. As indicated by the green circle in Figure 11, the 2016-2018 regression results, which represent the period after the Aliso Canyon incident, estimate that average monthly gas commodity procurement costs for SoCalGas customers was approximately $1.82/bill higher than it would have been without the Aliso Canyon limitations.. The 2016 results in Figure 12 estimate that average monthly gas commodity procurement costs for SoCalGas customers were approximately $1.32/bill higher than they would have been without the Aliso Canyon limitations relative to the control group during the year. Next, the 2017 results in Figure 13 estimate that average gas commodity procurement costs for SoCalGas customers were approximately $1.89/bill higher than they would have been without the Aliso Canyon limitations relative to the control group in 2017. Lastly, the 2018 result in Figure 14 estimate that average gas commodity procurement costs for SoCalGas customers were approximately $2.25/bill higher than they would have been without the Aliso Canyon limitations relative to the control group in 2018.

Figure 11: 2016-2018 Time Period Regression Results

```
t test of coefficients:

            Estimate Std. Error  t value             Pr(>|t|)
(Intercept) 19.53878    0.22372  87.3366 < 0.0000000000000022 ***
treated     -5.84993    0.22420 -26.0923 < 0.0000000000000022 ***
time        -4.51913    0.26714 -16.9170 < 0.0000000000000022 ***
did          1.81794    0.26779   6.7887       0.00000000001131 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

Figure 12: 2016 Time Period Regression Results

```
t test of coefficients:

            Estimate Std. Error  t value             Pr(>|t|)
(Intercept) 19.53878    0.22372  87.3366 < 0.0000000000000022 ***
treated     -5.84993    0.22420 -26.0923 < 0.0000000000000022 ***
time        -5.45081    0.33611 -16.2174 < 0.0000000000000022 ***
did          1.31566    0.33699   3.9042           0.00009454 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

Figure 13: 2017 Time Period Regression Results

```
t test of coefficients:

             Estimate Std. Error  t value             Pr(>|t|)    
(Intercept) 19.53878    0.22372  87.3366 < 0.00000000000000022 ***
treated     -5.84993    0.22420 -26.0923 < 0.00000000000000022 ***
time        -3.41609    0.35705  -9.5675 < 0.00000000000000022 ***
did          1.88322    0.35800   5.2603          0.0000001438 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

Figure 14: 2018 Time Period Regression Results

```
t test of coefficients:

             Estimate Std. Error  t value              Pr(>|t|)    
(Intercept) 19.53878    0.22372  87.3366 < 0.00000000000000022 ***
treated     -5.84993    0.22420 -26.0923 < 0.00000000000000022 ***
time        -4.70552    0.31940 -14.7321 < 0.00000000000000022 ***
did          2.24517    0.32028   7.0099     0.000000000002385 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

In 2016, a maximum allowable inventory limitation of 15 Bcf and injection restrictions were placed on Aliso Canyon; however, the pipeline outages on Lines 235-2 and 4000 had not happened yet. Hence, the 2016 regression results estimate that the impact of the Aliso Canyon limitations on average gas commodity procurement costs was round $1.32 per bill that year. In 2017 and 2018, bills for the treatment group conflated the effects of pipeline outages and the designation of Aliso Canyon as an asset of last resort, making differentiation between the two factors impossible to deconstruct and quantify precisely. Accordingly, staff concludes that in 2017 and 2018 the interplay between both factors resulted in higher gas commodity procurement costs. Since the purpose of this analysis is to study the impact of Aliso Canyon limitations on ratepayers, and it was impossible to be precise about the impacts in 2017 and 2018, staff relies on 2016 data to conclude that the Aliso Canyon limitations caused bills for SoCalGas customers to increase by roughly $1.32 per bill.[10]

2.4 Summary of Difference-in-Difference Analysis Findings

Relative to average gas commodity procurement costs from 2013 to 2015, before the Aliso Canyon leak and limitations:

[10] The 2016 estimate may slightly undercount the impact of Aliso Canyon limitations, because the field was on maximum withdrawal until January 24, 2016, to reduce the pressure in the field and thereby decrease the amount of gas leaking. Therefore, gas commodity costs would not have been impacted by a lack of Aliso Canyon withdrawals in January, which is one of the coldest months of the year and thus can have an outsize impact on average gas commodity costs.

- The average gas commodity procurement cost for SoCalGas customers from 2016 through 2018 increased by approximately $1.82 per bill;
- The average gas commodity procurement cost in 2016 increased by approximately $1.32 per bill. This likely includes most of the effect of the Aliso Canyon limitations, which began on January 24, 2016.
- The average gas commodity procurement cost in 2017 increased by approximately $1.89 per bill. This likely includes the partial effect of the pipeline outages, which began October 1, 2017, and the full effect of the Aliso Canyon limitations.
- The average gas commodity procurement cost in 2018 increased by approximately $2.25 per bill. This likely includes the full effect of the pipeline outages and the Aliso Canyon limitations.

3 Implied Market Heat Rate and Excess Electricity Costs Analyses

Natural gas plays a large role in the overall electricity system, providing a significant share of total electricity in California. While it is true that renewable energy is also a growing component, natural gas remains important for flexibility and operability in times where renewable energy fluctuates or decreases at night. Aliso Canyon provides natural gas supplies to a variety of customer types, of which natural gas-fired electric generation customers are the topic in this section. Aliso Canyon has historically played a critical role in the electric power system's ability to meet regional demand, particularly during the peak summer months. Constrained gas supply from and/or limitations on Aliso Canyon could lead to a decrease in the availability of natural gas in Southern California, which may necessitate the California Independent System Operator (CAISO) to import additional electricity into the region.

The CAISO operates the bulk transmission system and runs the daily electricity market for most of the state of California, primarily the three large investor owned utilities. The CAISO imports electricity by dispatching electric generators outside of Southern California. The electricity then travels via power lines to Southern California. This increased reliance on electricity imports into Southern California may raise electricity prices by dispatching less fuel-efficient generators or generators that are farther away and may face increased congestion costs. Therefore, the analyses in this section estimate the impact of the Aliso Canyon limitations on electric market efficiency and electric costs.

While Aliso Canyon provides gas supply to generators in the Los Angeles region, electricity prices in the CAISO are set uniformly across its entire jurisdiction, because the marginal generator sets the market clearing price.[11] If higher gas prices in the CAISO's Southern California region clear the

[11] CAISO price is made up of four components – Energy Clearing Price, Congestion, Transmission Losses, and GHG Emissions. The Energy Clearing Price is uniform across CAISO, but other components can vary. Local congestion, for example, can lead to prices that differ by location.

market and set the price, then electricity prices would also be increased throughout the CAISO's territory. In other words, Southern California's electricity prices would be elevated due to high gas prices, but electricity prices in Northern California would also rise even if gas prices in the north are low. The result is the perception of inefficient dispatches in Northern California.

Staff preformed two analyses to assesses California's electric market efficiency before and after the Aliso Canyon incident to estimate excess electricity costs caused by the Aliso Canyon limitations. The first analysis assesses market efficiency before and after the Aliso Canyon incident and pipeline outages by using the implied market heat rate (IMHR) approach. Then, the second analysis estimates excess electricity costs caused by the Aliso Canyon incident and pipeline outages.

3.1 Data Sources

The table below shows the variables and data sources for the Implied Market Heat Rate and Excess Electricity Costs Analyses**:**

Variable	Data Source
SoCalGas Citygate daily gas prices	NGI
PG&E Citygate daily gas prices	NGI
Henry Hub daily gas prices	NGI
Hourly Electricity Price and Generation by region	OASIS
Power Plants Data	CAISO settlement data

3.2 Methodology

3.2.1 Implied Market Heat Rate

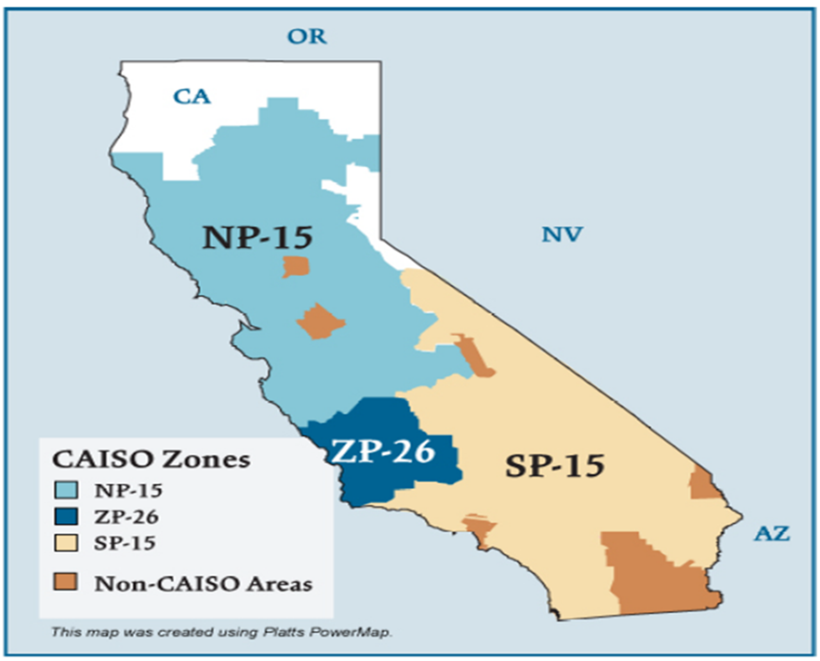
The IMHR analysis assesses impacts on electric prices in the CAISO market by comparing the implied market heat rate of electric generators dispatched before and after the Aliso Canyon incident. IMHR is defined as a calculation of the electric price divided by the natural gas price and is expressed as the number of million British thermal units (MMBtu) required to produce a megawatt hour (MWh) of electricity.[12] The purpose of the comparison is to determine if there is a significant cause and effect between gas curtailment and electric prices and to determine the economic effects in the electricity market of the Aliso Canyon limitations. This analysis does not specifically address the reliability of either the electric or natural gas system but instead seeks to quantify the estimated economic costs of reduced capacity at Aliso Canyon on the dispatch of electric generators.

[12] For the definition of IMHR according to the U.S. Energy Information Administration, see: https://www.eia.gov/tools/glossary/index.php?id=I:
A calculation of the day-ahead electric price divided by the day-ahead natural gas price. Implied heat rate is also known as the break-even natural gas market heat rate because only a natural gas generator with an operating heat rate (measure of unit efficiency) below the implied heat rate value can make money by burning natural gas to generate power. Natural gas plants with a higher operating heat rate cannot make money at the prevailing electricity and natural gas prices.

IMHR is not an indication of physical operations of the electric system or the actual heat rate of the power plants actually operating at a given time, but instead is used to estimate market efficiency by comparing actual electricity prices in the market to the estimated heat rate (amount of fuel burned to generate one MWh of electricity) that electricity price would equate to. As with heat rates, where lower heat rates are associated with more efficient power generating plants, a lower IMHR means a more efficient market, and a higher IMHR means a less efficient market.

Staff analyzed cost trends in the CAISO market to determine if the Aliso event led to an increase in IMHR (and underlying electricity costs) and thus dispatched less efficient plants. Staff calculated the IMHR for the Northern and Southern California parts of CAISO using North of Path 15 (NP15) and South of Path 15 (SP15) day-ahead CAISO market electricity prices ($/MWh). Figure 15 shows the CAISO territory.

Figure 15: CAISO Zones Map



IMHR is calculated as shown below. The day-ahead electricity price and generation data are collected from the CAISO's Open Access Same-Time Information System (OASIS) site. Staff calculated IMHR during the midday usage hours each day, from Hour Ending 6 am to Hour Ending 10 pm every day except Sunday.

3.2.1.1 Implied Market Heat Rate Calculation for Northern California:

$$\boldsymbol{Implied\ Market\ Heat\ Ratet} = \frac{\boldsymbol{DALMPt}}{\boldsymbol{DNGPt}}$$

Where:

Implied Market Heat Ratet is the daily implied market heat rate in Northern California

DNGPt is the daily gas price for PG&E Citygate

DALMPt is the daily day-ahead weighted average price $= \frac{\sum_h^H \boldsymbol{LMPh * GENh}}{\sum_h^H \boldsymbol{GENh}}$

LMPh is the hourly locational marginal price for NP15

GENh is the hourly generation for the Northern California transmission access charge (TAC) area. It is represented as TAC_NORTH in OASIS

$\sum_h^H \boldsymbol{GENh}$ is the total generation for all 24 hours in each day for the TAC_NORTH area

3.2.1.2 Implied Market Heat Rate Calculation for Southern California:

$$\boldsymbol{Implied\ Market\ Heat\ Ratet} = \frac{\boldsymbol{DALMPt}}{\boldsymbol{DNGPt}}$$

Where:

Implied Market Heat Ratet is the daily implied heat rate in Southern California

DNGPt is the daily gas price for SoCal Citygate

DALMPt is the daily day-ahead weighted average price $= \frac{\sum_h^H \boldsymbol{LMPh * GENh}}{\sum_h^H \boldsymbol{GENh}}$

LMPh is the hourly locational marginal price for SP15

GENh is the hourly generation for the Southern transmission access charge (TAC) area. It is represented as TAC_ECNTR and TAC_SOUTH in OASIS[13]

$\sum_h^H \boldsymbol{GENh}$ is the total generation for all 24 hours in each day for the TAC_ECNTR and TAC_SOUTH area combined

3.2.2 Excess Electricity Cost Analysis in SP15 and NP15

Staff estimated the total excess cost customers paid for electricity in SP15 and NP15 to determine the economic impact of the Aliso Canyon limitations on the electricity market. Due to differences between SP15 and NP15, staff performed different analyses in each area. For SP15, staff used regression to estimate what SoCal Citygate gas prices would have been in the absence of Aliso limitations.

For NP15, electricity prices were impacted by the Aliso Canyon limitations due to their effects on SP15 and the single electricity clearing price throughout the CAISO area. For this reason, staff used

[13] In OASIS, CAISO is made up of four TAC areas; TAC_NORTH corresponds to NP15 and TAC_ECNTR and TAC_SOUTH correspond to SP15. TAC_NCNTR is neither NP15 or SP15 and not part of the analysis.

regression analysis to predict the electricity prices that would have occurred in the absence of Aliso limitations and pipelines outages. Then staff used spark spread analysis to estimate total excess cost for electricity occurring from moderate PG&E Citygate gas prices and high electricity clearing prices in CAISO. Due to the difference in situations between SP15 and NP15, two different analyses were used:

- NP15 had normal gas prices (from PG&E Citygate) and high electricity prices (from CAISO clearing market). Since electricity prices were affected by the Aliso limitations, staff predicted what the electricity prices would have been using regression analysis.
- SP15 had high gas prices at SoCal Citygate largely due to the Aliso limitations and pipeline outages and the resulting high electricity prices. Since in SP15 SoCal Citygate prices were affected by the Aliso limitations, staff predicted what the gas prices would have been using regression analysis.

3.2.2.1 SP15 Estimate of Excess Electricity Cost Due to High Electricity Prices

Staff used the following steps to estimate the excess costs for electricity in SP15:

1. Staff used regression analysis to predict SoCal Citygate gas prices from 2010 to 2015 to determine the historical trend ($/MMBtu). Staff then used that relationship to predict what gas prices would have been in 2016-2018 without the Aliso limitations from analysis of trends before the Aliso event.
2. Staff used a correlation analysis to determine that SoCal Citygate prices trended closely with Henry Hub prices (better than Permian and San Juan Basins).
3. Staff used regression analysis to quantify the relationship between Henry Hub and SoCal Citygate prices fitting the trend to 2010 to 2015 data before the Aliso event. The model is described in the equation below:
    a. SoCal Citygate = β0 + β1* Henry Hub + Error Term.
4. Staff applied regression to estimate expected gas prices after Aliso event (2016-2018).
5. The heat rate was assumed to be 8 MMBtu/MWh, which is a reasonable number based on the settlement data and based on CEC table: QFER CEC-1304 Power Plant Data Reporting.[14]
6. Estimated electricity prices in 2016 to 2018 were calculated by multiplying predicted gas prices by the assumed heat rate and total actual generation from thermal electric plants (based on CAISO settlement data).

Example of the calculation

- Assume the actual gas price is $4/MMBtu and the predicted prices is $3/MMBtu.
- Electricity cost $\left(\frac{\$32}{MWh}\right)$= Gas Price $\left(\frac{\$4}{MMBtu}\right)$* Heat Rate $\left(\frac{8\ MMBtu}{MWh}\right)$

[14] 1 https://www.energy.ca.gov/2017publications/CEC-200-2017-003/CEC-200-2017-003.pdf

- Electricity cost ($\frac{\$24}{MWh}$)= Gas Price ($\frac{\$3}{MMBtu}$)* Heat Rate ($\frac{8\,MMBtu}{MWh}$)
- The excess $ paid per MWh is: $32-$24 = $8/MWh
- The total excess paid is $8 for each MWh of total generation by gas-fired power plants.

3.2.2.2 NP15 Estimate of Excess Electricity Cost Due to High Electricity Prices

The spark spreads for NP15 use historical and predicted day-ahead electricity prices at NP15 and the actual historical gas price at PG&E Citygate. Staff estimated the excess costs for electricity in NP15 by using the NP15 day-ahead price at NP15 from 2014 and 2015 to fit a regression model, then used that trained regression model to predict what electricity prices would have been during 2016 through 2018. The best fitting model staff found was the model which predicted the log of electricity prices. The best fitted model is described below:

A spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of profitability. Spark spread analysis assumes that the gas price is the only marginal cost. Specifically, spark spread is defined as the difference between the revenue received by the generator for selling power and the cost of the gas in $ per MMBtu used to generate that power. The following formula was used to calculate the spark spread:

Spread ($\frac{\$}{MWh}$)= LMP ($\frac{\$}{MWH}$) – Gas Price ($\frac{\$}{MMBtu}$)* Heat Rate ($\frac{MMBtu}{MWh}$)

Log(electric prices)= electric demand + log(Henry Hub) + dummy (Mon) + dummy(Tue) + dummy(Wed) + dummy(Thu) + dummy(Fri) + dummy(Sat) + dummy(Jan) + dummy(Feb) + dummy(Mar) + dummy(Apr) + dummy(May) + dummy(Jun) + dummy(Jul) + dummy(Aug) + dummy(Sep) + dummy(Oct) + dummy(Nov) + error term

a) NP15 Estimate of Excess Electricity Cost due to High Electricity Prices

Staff used the following steps to estimate the excess costs for electricity in NP15:

1. Spark spread is defined as the difference between the revenue received for selling power and the cost of gas used to generate power (i.e. the cost per MWh).
2. Spread ($\frac{\$}{MWh}$)= LMP ($\frac{\$}{MWH}$) – Gas Price ($\frac{\$}{MMBtu}$)* Heat Rate ($\frac{MMBtu}{MWh}$)
3. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of profitability.
4. The spread analysis assumes that the gas price is the only marginal cost.
5. The spark spreads for NP15 use day-ahead electricity prices at NP15 and the gas price at PG&E Citygate.
6. The predicted spark spreads use predicted energy price and gas prices at PG&E Citygate. Staff used the price for day-ahead at NP15 from 2014 and 2015 to fit a model then predict the electricity price. The model used to predict energy price is described below:

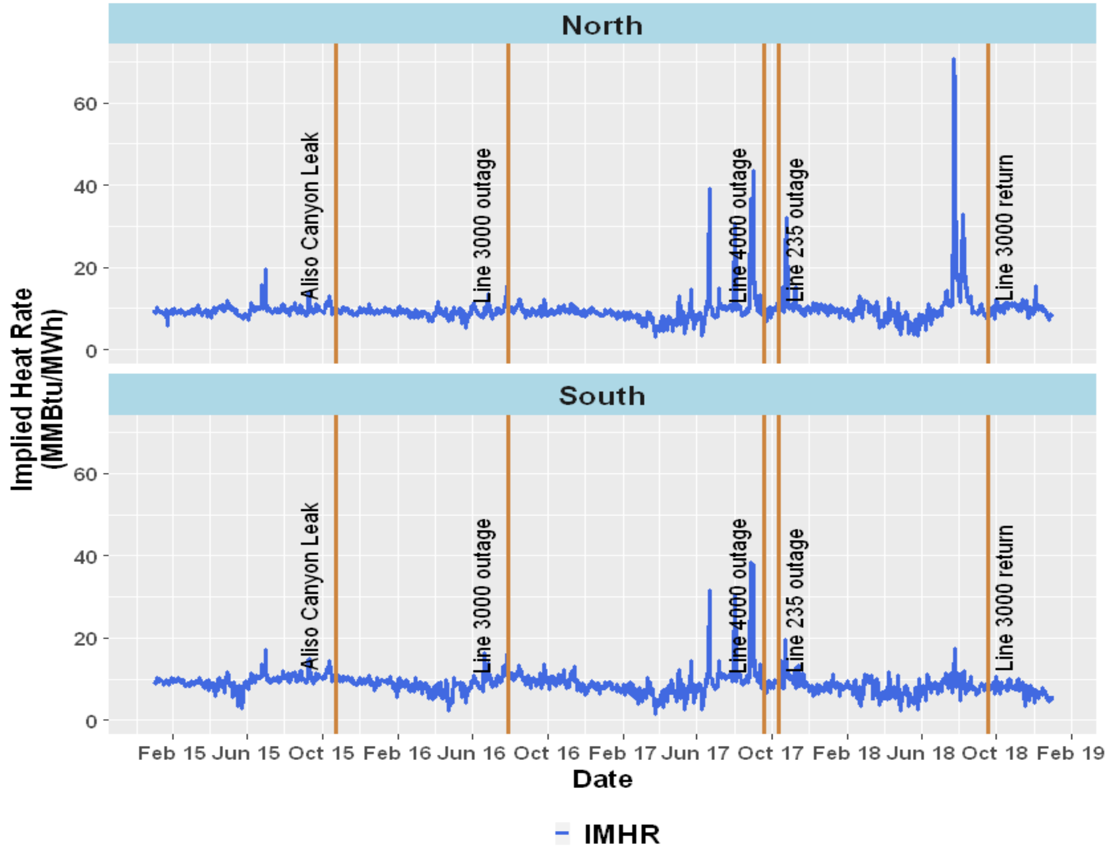
7. The model does not include variables for all months or all days of week, since doing so would prevent our ability to determine if any of the day of week or month variables are significant since they are collinear. This is called multicollinearity.
8. The heat rate is assumed to be 8 MMBtu/MWh, which is a reasonable number based on the settlement data and based on CEC table (same table staff used in the previous section).

3.3 Results

3.3.1 Implied Market Heat Rate Results

Figure 16 represents the daily IMHR in NP15 (shown in the top-half as North) and SP15 (shown in the bottom-half as South). The graphs show a stable and low IMHR and a consistent correlation between IMHR in NP15 and SP15 until mid-2017. Also, the graphs show a significant IMHR increase in NP15 in mid-2017, which is when the SoCal Citygate price starts to increase beyond its historical range. The large spikes in IMHR during 2015, which is before the Line 235-2 and 4000 outages, are due to high electricity use and demand across CAISO, as evidenced by the symmetry between IMHR in the North and South during 2015 until 2017. High IMHR in NP15 is the result of low gas prices and higher than normal electricity prices in NP15. Recall that electricity prices in the CAISO's NP15 and SP15 are uniform and set by the marginal resource that clears the market. Therefore, higher gas costs in Southern California lead to higher electricity costs from the Southern California gas-fired electric generators. If one of the Southern California gas-fired electric generators is the market clearing generator in the CAISO, then electricity prices are also higher in Northern California despite the lower gas costs.

Figure 16: Daily IMHR for Weighted midday Hours, Hours Ending 6-22



[15]

Figure 17 represents the average monthly IMHR in NP15 and SP15. The graphs show IMHR increased in NP15, shown in red, when SoCal Citygate prices, shown in orange, increased relative to PG&E Citygate, shown in grey. This increase was most significant in July and August 2018. IMHR in NP15 increased when SoCal Citygate prices increased. Gas prices in SoCal Citygate were a major contributor to IMHR increase in NP15 during July and August 2018.

[15] Line 4000 returned to service on December 22, 2017 but operated at reduced pressure.

Figure 17: Monthly IMHR

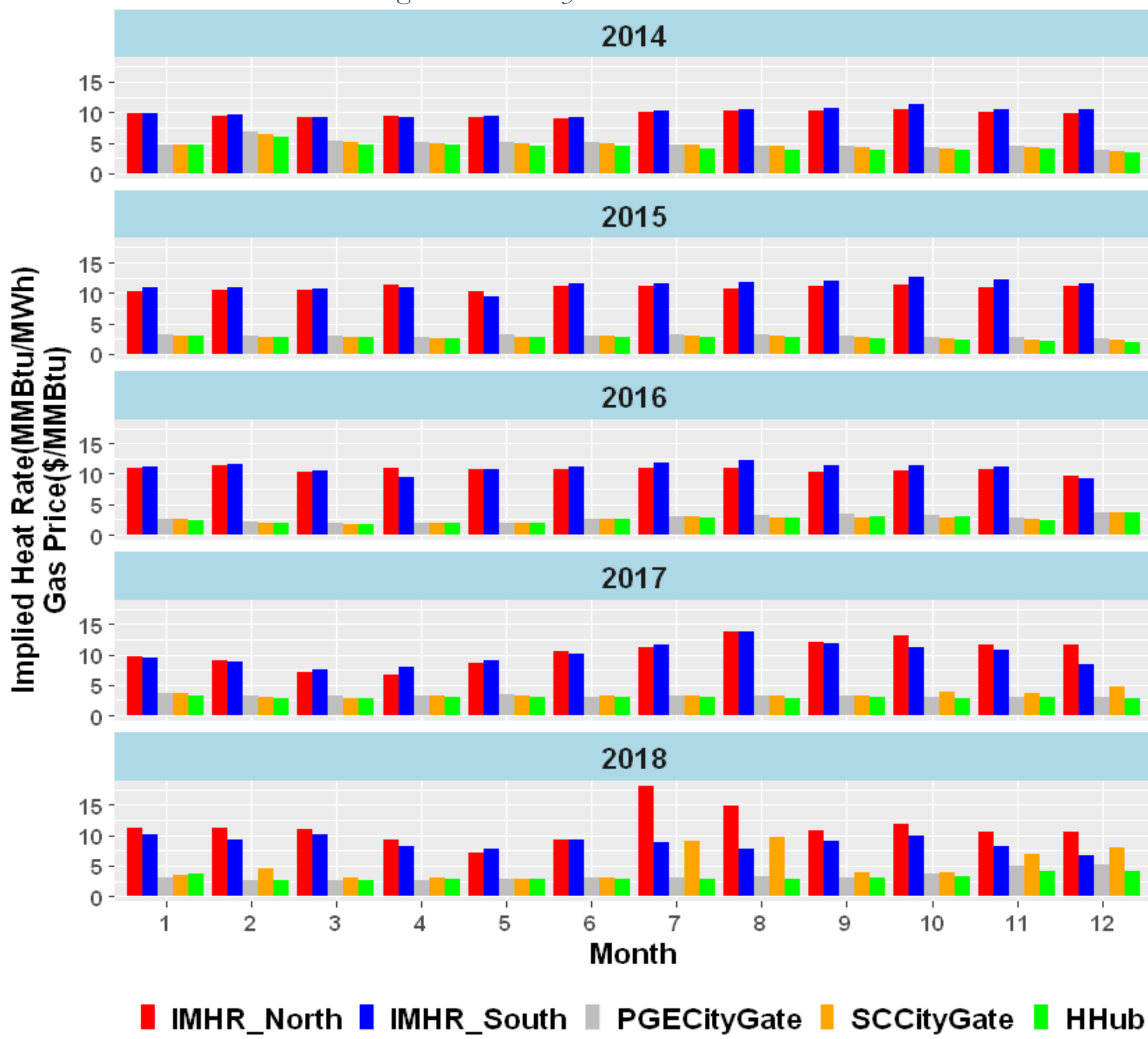


Figure 18 presents ranked IMHR for the highest 160 hours in NP15 and SP15 for five years (2014-2018) and shows the differences in IMHR particularly between NP15 and SP15 in 2018. The graphs rank IMHR from highest to lowest and show a line for each year; patterns of IMHR in the top 160 hours of each year appear stable and low until the middle of 2017. During 2018, IMHR is very high in NP15 but normal or similar to other years in SP15; this is a significant trend showing that, while electricity prices in SP15 made sense given the dramatically higher gas prices at SoCal Citygate, electricity prices in NP15 resulted from high CAISO prices and could not be explained by high gas prices at PG&E Citygate. Instead, they illustrate significant IMHR increases, and thus significant excess revenues paid to electricity generators. The top 100 hours in 2017 and 2018 show a substantial increase in IMHR, despite other significant factors that were driving electric prices lower, such as: increased renewable generation, increased hydro generation, and a transition to more efficient thermal generation. High IMHR in the top 100 hours of 2018 corresponded to higher natural gas prices at SoCal Citygate and the embedded gas price effects of expected Operational

Flow Order (OFO) penalties on the SoCalGas system. OFO penalties are significant here since noncore electric generation customers are not able to use storage to mitigate OFO penalties. When electric generators anticipate OFO penalties in the next day, they can add the penalty amount to their day ahead bid into the electricity market. If they are needed to generate, they will receive sufficient revenue to cover potential OFO penalties.

Figure 18: IMHR Duration Curve – Top 160 highest IMHR Hours of the Year-

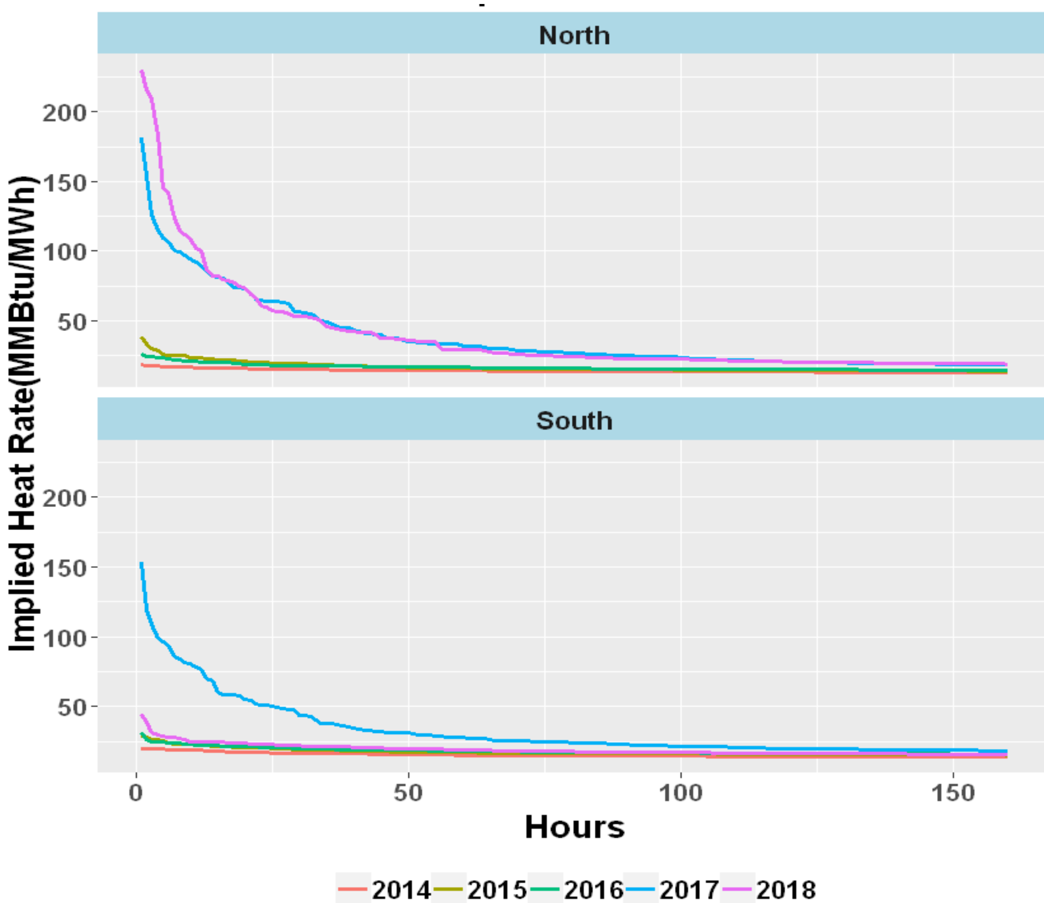


Figure 19 represents the IMHR based on the electric demand level in NP15 and SP15 for five years (2014-2018). Gas generation is marginal, particularly at high demand. Normally IMHR is expected to increase at high demand (75 percent-100 percent quartile), but the effect is much more pronounced in 2018 as the graph illustrates. Also, the graph shows that normally IMHR is higher in SP15. However, after 2017, NP15 IMHR is higher. IMHR increases even as overall demand and generation decreases. The decrease in demand and generation is illustrated in Figure 20.

Figure 19: IMHR vs Load

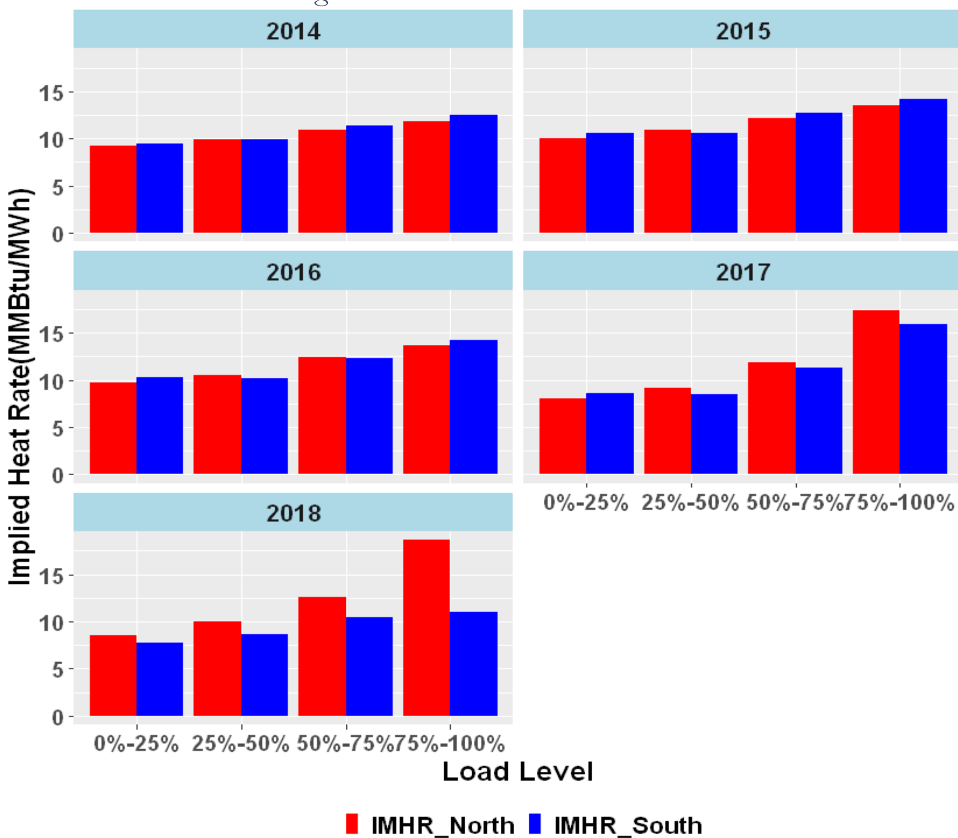


Figure 20: Generation and Demand from 2014-2018 (MWh)

Year	Gen_NP15	Load_NP15	Gen_SP15	Load_SP15
2014	62,685,609	66,090,217	52,834,786	83,144,559
2015	62,953,130	66,388,093	55,683,578	82,102,337
2016	60,101,115	65,593,854	47,802,058	81,861,354
2017	60,893,390	64,808,895	51,170,408	82,539,875
2018	59,279,306	61,964,336	47,435,718	81,229,788

3.3.2 Electricity Cost Analysis in SP15 and NP15

The Excess Electricity Costs study assesses California's electric market efficiency before and after the Aliso Canyon incident and estimates excess electricity costs caused by the Aliso Canyon limitation. This study found electricity costs in SP15 began to increase in October 2017, concurrent with the outage of Line 235-2. Staff estimated that electric customers paid about $599 million in excess costs in 2018 due to pipeline outages and the Aliso restrictions. This estimate does not include other electricity costs such as administration costs or purchases of imported electricity, so it is likely an underestimate.

3.3.2.1 SP15 Estimate of Excess Electricity Cost Due to High Electricity Prices

As mentioned in the methodology section, SP15 regression results show that SoCal Citygate prices can be predicted from Henry Hub prices. As the green circle in Figure 21 illustrates, a one-dollar change in Henry Hub price correlates to about 93 cents change to the SoCal Citygate Price. Also, the figure shows a 90 percent R2 which is a measure of how well the model explains the interaction between the variables. The low p-value in the red circle indicates that the null hypothesis can be rejected. The p-value tests the null hypothesis that there is no relationship between the Henry Hub price and SoCal Citygate price. To address the heteroskedasticity and serial correlation issues, robust standard errors were used.

Figure 21: SP15 Regression Results

```
Coefficients:
            Estimate Std. Error t value Pr(>|t|)
(Intercept) 0.442317   0.024100   18.35   <2e-16 ***
HH          0.924572   0.006464  143.03   <2e-16 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.2659 on 2185 degrees of freedom
Multiple R-squared:  0.9035,    Adjusted R-squared:  0.9035
F-statistic: 2.046e+04 on 1 and 2185 DF,  p-value: < 2.2e-16
```

Figure 22 presents the predicted SoCal Citygate gas prices compared to historical SoCal Citygate prices. The predicted prices are the result of the regression described in Section 3.2.2.1. The graph indicates that the predicted SoCal Citygate prices deviated strongly from the historical price trend after the after Line 235 outage in October 2017. The most extreme deviations occur in July and August 2018 and are the source of significant excess costs to electricity customers.

Figure 22: Actual and Predicted Gas Prices for SoCal Citygate

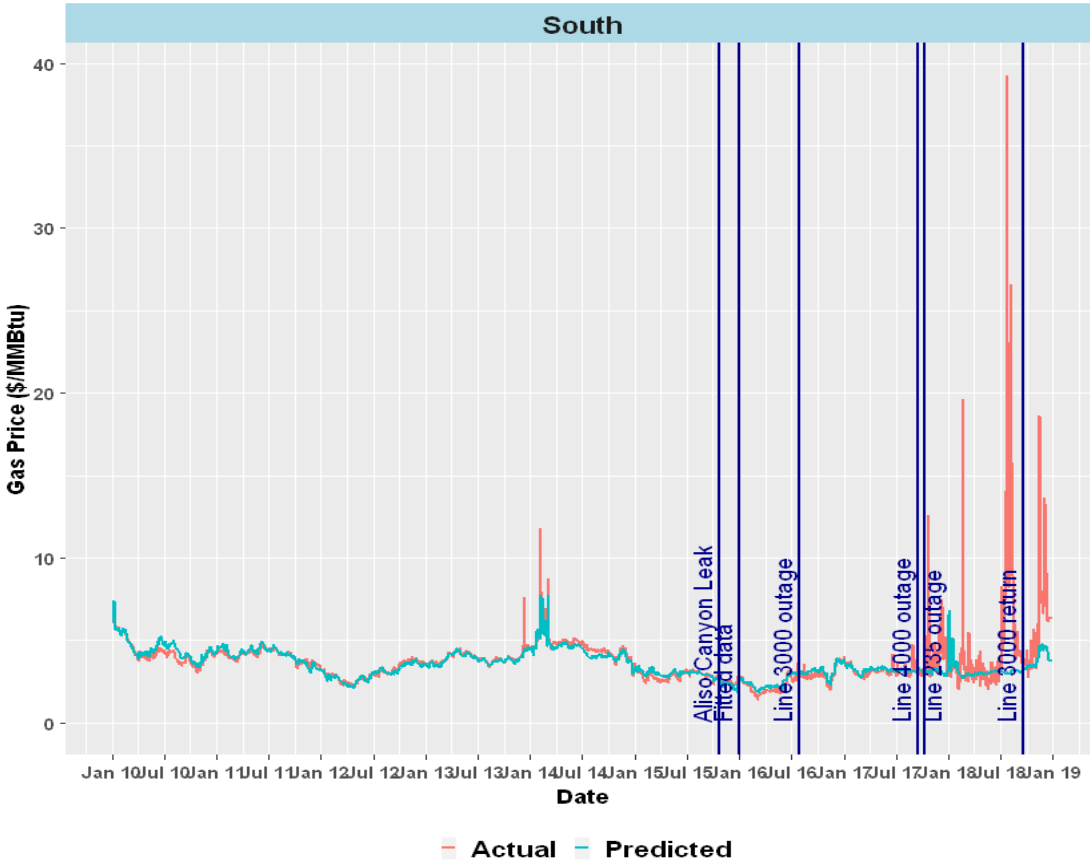


Figure 23 represents the SP15 total monthly predicted and actual electricity cost. The graph shows that, after the Line 235 outage in October 2017, the difference between predicted and actual electricity cost starts to become significant, particularly in the summer of 2018 when the observed difference between predicted and actual electricity costs rose to $200 million per month.

Figure 23: Predicted and Actual Electricity Cost for SP15

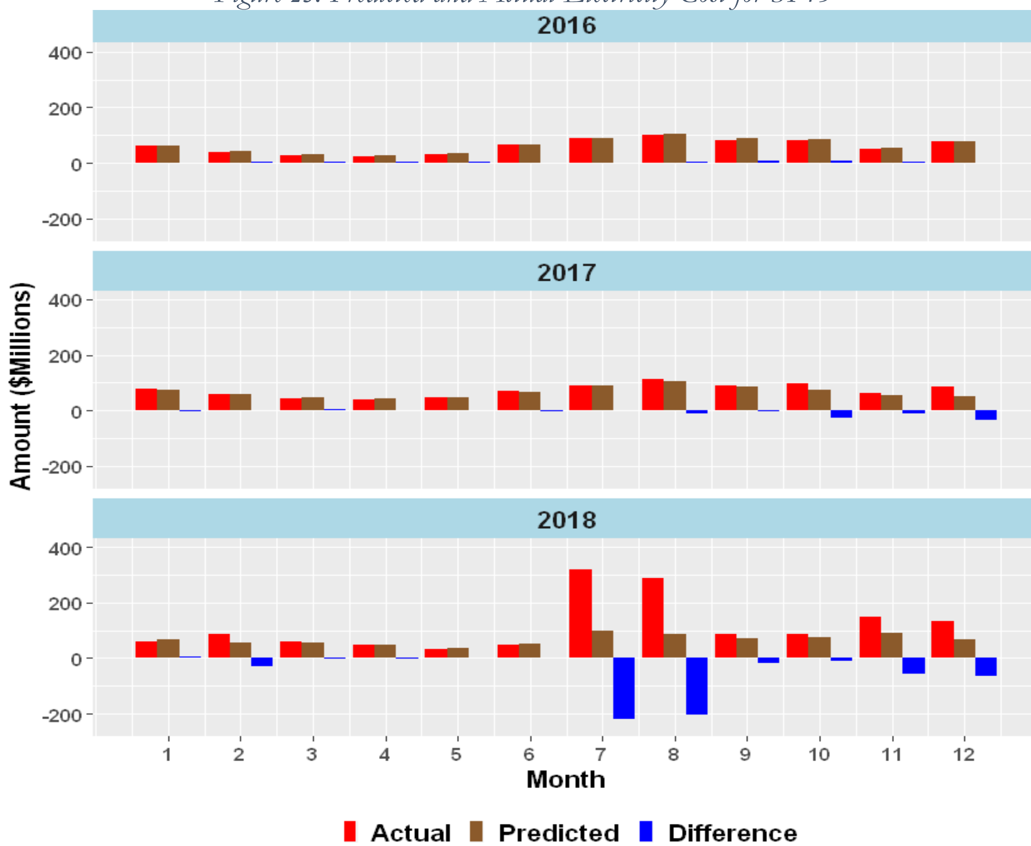


Figure 24 illustrates the excess cost that electric customers paid. This calculation is likely an underestimate of the excess dollar amount paid by the electric ratepayers in the south since it doesn't account for any increase in imported power caused by gas curtailments or other electric costs other than gas prices.

Figure 24: Estimated Excess Cost for SP15 (rounded to $ millions)

Year	Actual SP15 Cost	Predicted SP15 Cost	Estimated Excess Cost
2016	$728.9	$769.3	-$40.5
2017	$878.3	$802.3	$76.1
2018	$1,399.3	$800.5	$598.8

3.3.2.2 NP15 Estimate of Excess Electricity Cost Due to High Electricity Prices

Staff used regression analysis to predict electricity prices in NP15. Figure 25 is a copy of the regression results from our analysis using R Suite, and several conclusions can be made. The null hypothesis is that there is no relationship between electric demand, represented as load in the regression results, and natural gas variables. The regression results show that a 1 percent change in Henry Hub prices lead to 0.71 percent change in the electricity prices. The electric demand and natural gas variables have low p-values indicating that staff can reject the null hypothesis that the electric demand and natural gas variables have no effect. Also, the results show an 87 percent adjusted R-squared, which shows that 87 percent of the variation in NP15 Citygate prices can be explained by the variables included in the regression, specifically electric demand and the log of gas prices at Henry Hub. Staff used adjusted R-squared to avoid the issue of overestimating the effect of the extra variables. To address the heteroskedasticity and serial correlation issues, robust standard errors were used.

Figure 25: NP15 Regression Result

```
Coefficients:
              Estimate Std. Error t value Pr(>|t|)
(Intercept)  1.865e+00  5.937e-02  31.420  < 2e-16 ***
load         9.064e-05  5.592e-06  16.208  < 2e-16 ***
log_HH       7.081e-01  1.113e-02  63.621  < 2e-16 ***

Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1

Residual standard error: 0.08019 on 710 degrees of freedom
Multiple R-squared:  0.8713,   Adjusted R-squared:  0.8679
F-statistic:   253 on 19 and 710 DF,  p-value: < 2.2e-16
```

Figure 26 represents the NP15 predicted electricity prices compared to actual historical electricity prices. The predicted prices are based on the NP15 regression result. Predicted prices and actual prices overlap quite well until 2017, when trends begin to deviate. There are some deviations before the Aliso event such as an extreme weather event in 2014, but in 2017 and beyond, pipeline outages and the Aliso limitations combine to cause actual trends to deviate significantly from predicted patterns that would have happened without the Aliso event.

Figure 26: Actual and Predicted Electricity Prices for NP15

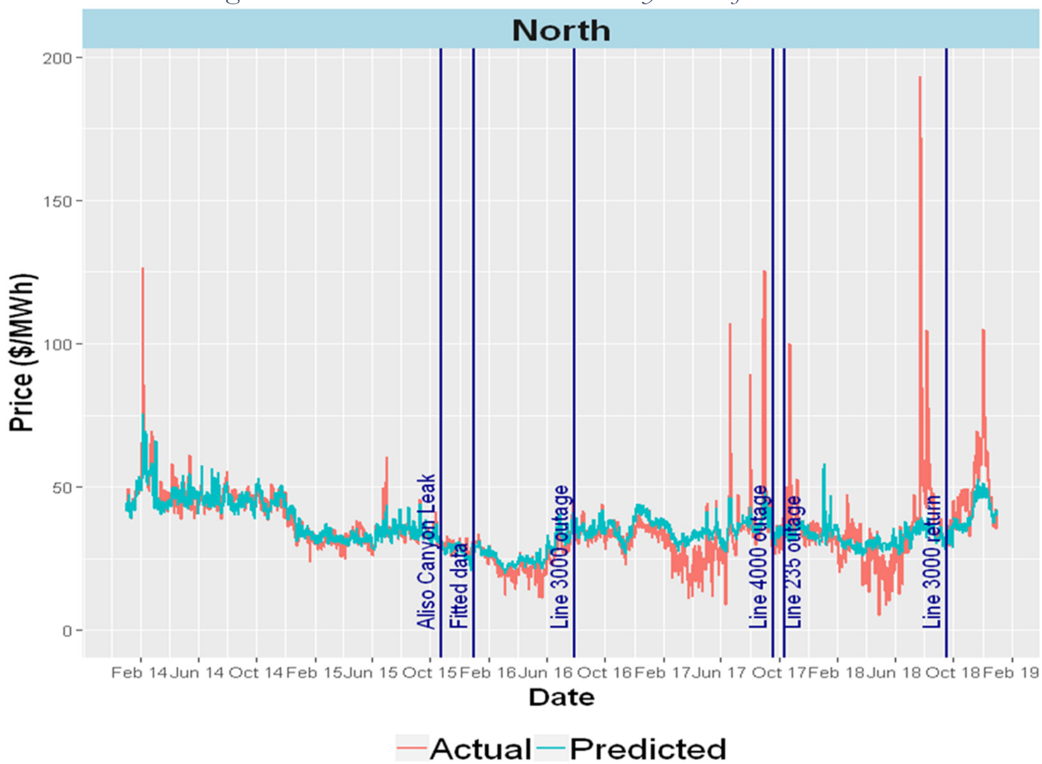


Figure 27 graphs the predicted spark spread and the actual spark spread in NP15 for five years (2014-2018). The graphs show a substantial difference between the amount electric generators in NP15 earned (red bar – Spark) and what they would have earned under normal CAISO electricity prices (brown bar – Spark_pred) in July and August of 2018.

Figure 27: Actual and Predicted Spark Spread for NP15

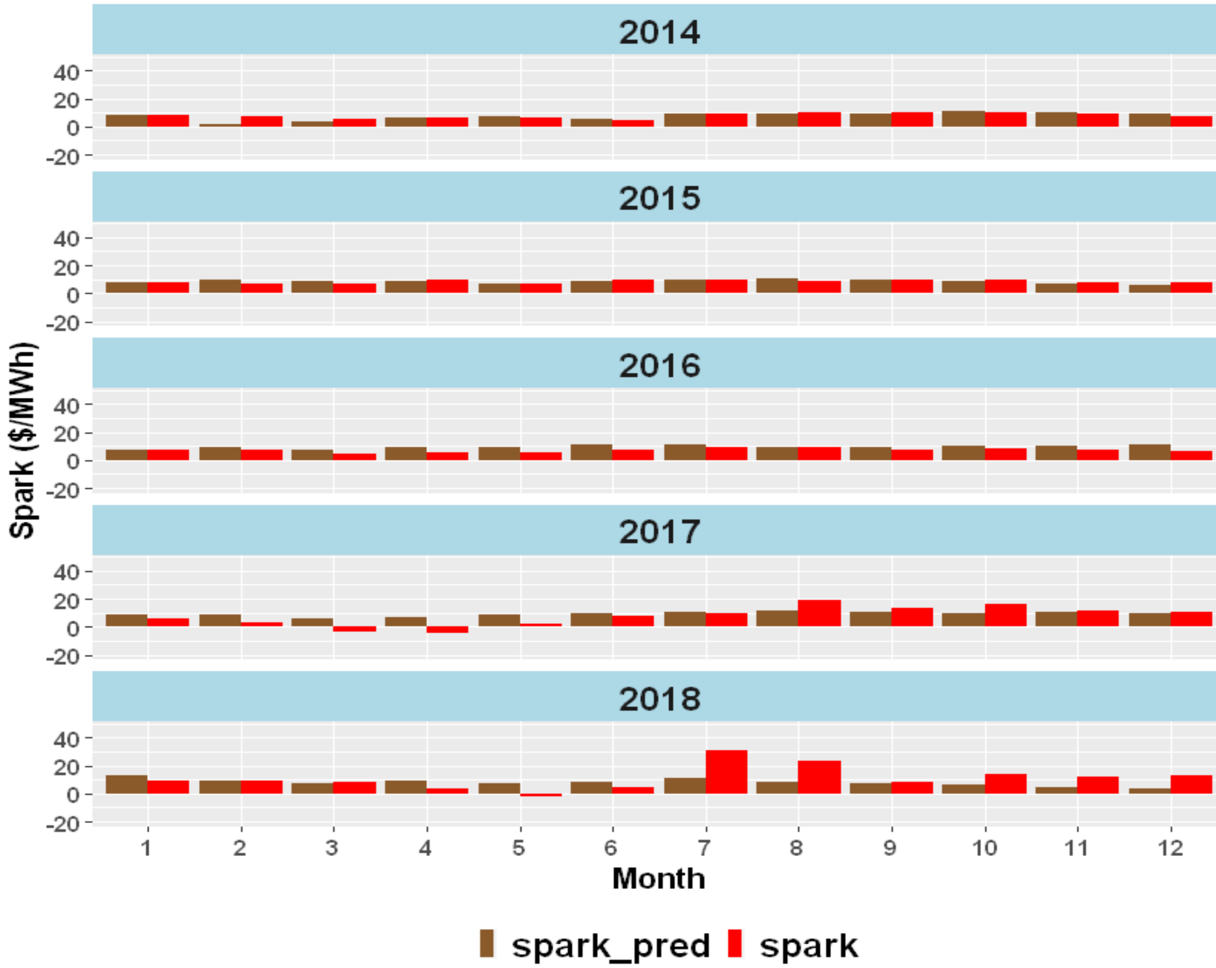


Figure 28 represents the total monthly excess cost in NP15 for five years (2014-2018), which is the actual amount in excess of reasonable power prices that electric generators in NP15 received. As illustrated in the previous sections, the gas prices at SoCal Citygate were trending similarly to PG&E and Henry Hub until July 2017; the increase in the cost of electricity prior to these months was consistent with predictions. In October, November and December 2017 (after the Line 235-2 outage), SoCal Citygate gas prices increased in excess of historical trends and led to higher electricity prices across CAISO, including in NP15. In 2018 the increase of excess electricity cost in NP15 was due to high gas prices at SoCal Citygate.

Figure 28: Actual and Predicted Excess Cost for NP15

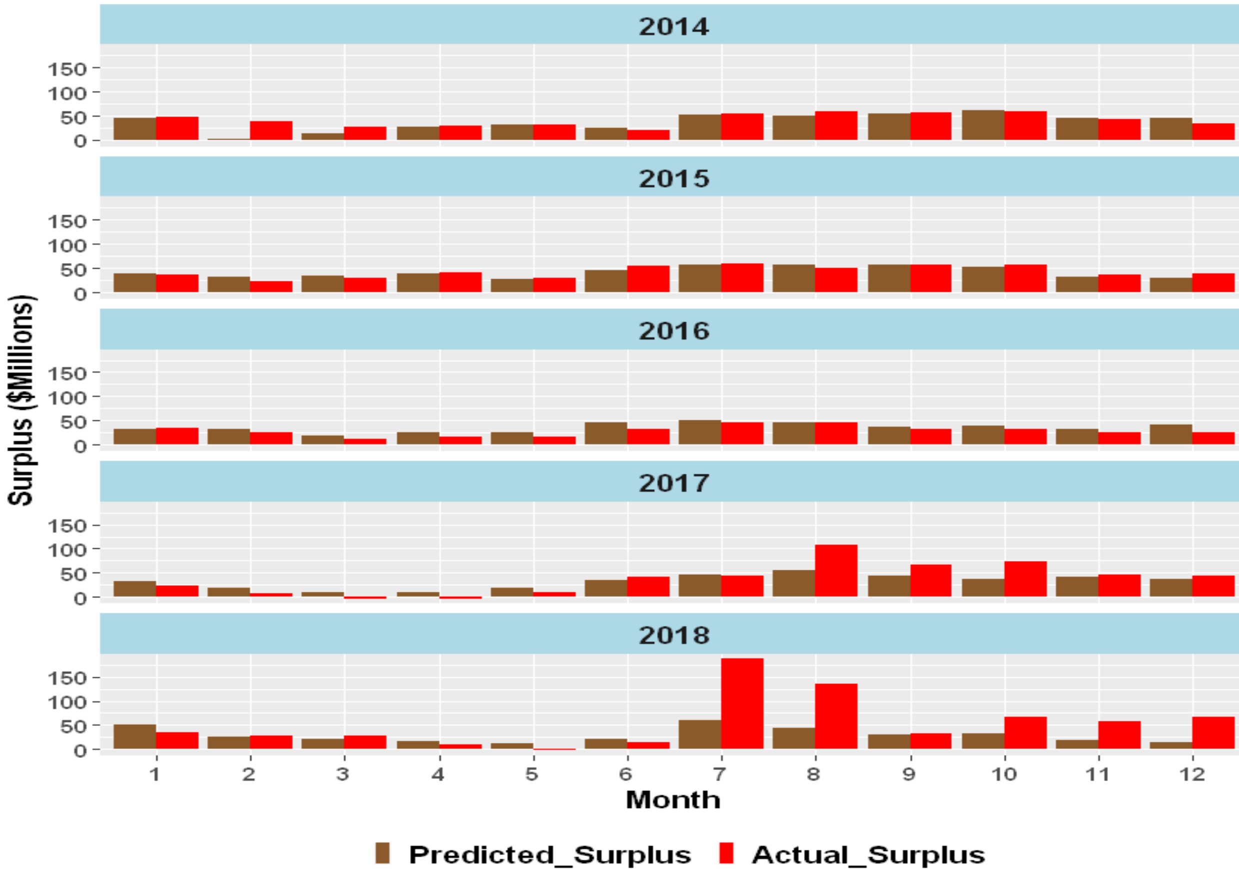


Figure 29 shows the excess cost that electric customers paid during the years 2016-2018. This is the difference between predicted costs and actual historical costs.

Figure 29: Excess Electricity Cost in NP15 (rounded to $ millions)

Year	Actual excess revenues net of operating costs ($MM)	Predicted excess revenues net of operating costs ($MM)	Excess Electricity Cost ($MM)
2016	$346.5	$425.1	-$78.5
2017	$457.1	$382.1	$75
2018	$660.5	$343.5	$317

3.4 Summary of IMHR and Excess Electricity Costs Findings:

- The analysis shows significant increases occurred in market inefficiency (IMHR) in NP15 compared to SP15 in 2018 relative to 2017. The increases occurred despite the decrease of electric demand and overall generation in 2018, which should have increased market efficiency.

- After the Line 235-2 and Line 4000 outages in October 2017, IMHR was predominantly higher in NP15 compared to SP15.
- Staff concludes that the increase in IMHR in 2018 can be explained by gas price volatility and higher SoCal Citygate prices. Furthermore, the volatility and higher prices were caused by both the pipeline outages and the limitations on the use of Aliso Canyon, and not one or the other reasons in isolation.
- In times of high gas use and/or gas scarcity, gas-fired electric generators can price in the expectation of OFO penalties into their electric generation bids, even when OFOs do not end up being called.
- Electricity costs in SP15 began to increase in October 2017, concurrent with the outage of Line 235-2. Staff estimates that electric customers in SP15 paid about $599 million in excess costs in 2018 due to the pipeline outages and the Aliso Canyon limitations.
- This estimate does not include other electricity costs, such as administration costs or purchases of imported electricity, so it is likely an underestimate.
- The excess electricity costs were not isolated to CAISO's SP15 zone; there were excess costs in NP15 as well. Staff estimated excess costs by analyzing the relationship between PG&E Citygate prices and predicted electricity prices, then comparing it to the relationship between PG&E Citygate prices and actual electricity prices. Excess costs totaled about $317 million in 2018.

(END OF ATTACHMENT A)