California Public Utilities Commission

May 2019

Actions to Limit Utility Cost and Rate Increases

Public Utilities Code Section 913.1 Annual Report to the Governor and Legislature

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Executive Summary

The California Public Utilities Commission (CPUC or Commission) issues this 2019 Senate Bill (SB) 695 report pursuant to Public Utilities Code Section 913.1, which requires that the Commission publish recommendations that can be undertaken over the succeeding 12 months to limit utility cost and rate increases. California's Investor Owned Utilities (IOUs)[1] are also required by statute to issue their own reports with recommended cost mitigation measures.

The 2019 report presents an opportunity to investigate, identify and examine underlying trends in utility costs and rates during a period of extensive energy industry transformation, and to illuminate the many policy choices and tradeoffs facing decision-makers that promote long-term affordability.

Climate change, wildfire severity, aging infrastructure, and tectonic shifts in technology and the retail marketplace create risks that California electricity bills will become unaffordable for some customers and have the potential to threaten the viability of California's clean energy policies. Increasing retail choice and distributed energy resource (DER) offerings pose challenges to effectively managing costs for ratepayers and make forecasting rate impacts difficult. Nevertheless, despite this uncertainty and unpredictability, this report probes the depths of the capital and operations costs for many of our priority resource development budgets and timelines. In so doing, the report offers an illustrative approximation of incremental rate and bill impacts, as well as tools for evaluating the affordability of our policy choices for customers.

Key highlights from this report include:

- The total System Average Rate (SAR) of each of the three IOUs historically tracked close to inflation in a gradual upward trend until 2013. Since then, the annual percentage change has been generally trending above the annual inflation rate, with SDG&E's total SAR increasing at a markedly faster rate than inflation.

- Historically, while California's electricity rates have been higher than most of the nation, bills have been lower because usage in California is low compared to most of the United States. However, low usage is no longer offsetting rate impacts in some areas of the state, which could lead to a growing trend of bills exceeding national averages.

- These rising rates and bills stem from declining utility sales, while revenue requirements continue growing to meet statutory mandates and operational needs. This means that fixed costs are paid for by fewer customers.

[1] *See* Public Utility Code §913.1(b): In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases.

- Rate and bill impacts based on 2019 budgets for several programs have been estimated for the residential customer class as a first step in developing a tracking tool that may be used by decision-makers to better evaluate programs mandated by statute.

- Rate and bill impacts based on proposed 2019 activities in the IOUs' Wildfire Mitigation Plans, submitted pursuant to California Senate Bill 901 (SB 901), have been estimated for the residential customer class to illustrate potential cost impacts. The costs of proposed utility wildfire mitigation plans could result in increases of up to seven percent in monthly bills for some customers.

- Rate and bill impacts from liability of past wildfires are still unknown, but if ratepayers are required to pay large portions of these costs, rates and bills could dramatically increase beyond the costs of existing programs and wildfire mitigation plans.

1. Introduction

The SB 695 Report has traditionally examined utility costs at the total system level.[2] However, starting this year, we take a sharper focus on breaking down costs reflected in total SAR corresponding to bundled customers to examine these costs through the lens of affordability for the residential customer class.

Utility costs to serve energy can be broken down into two categories: 1) operating expenditures coupled with a required return on investment and 2) public policy program costs. In this year's SB 695 Report, the funds that each utility is authorized to collect in rates — commonly referred to as revenue requirements — are presented for selected legislative programs. By presenting the revenue requirement in this way, the CPUC hopes to move forward with developing tools that recognize the costs and benefits of policy mandates by separating them from ongoing utility operating costs and infrastructure investment activities in order to better inform decision makers' policy choices.

Lower Energy Usage May No Longer Be Enough to Limit Bill Impacts

Electricity Costs

Total SAR, defined as an IOU's total authorized revenue requirement divided by total kilowatt-hour (kWh) sales, is a measurement of an IOU's cost to serve electricity to its customers. Consideration of actions to limit utility costs should begin with an examination of SAR. Historically, the total SAR of each of the three major electric investor owned utilities (IOUs), Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), has generally tracked inflation in a gradual upward trend. However, starting in 2013, the average annual change in SAR began to outpace the inflationary rate, with SDG&E's SAR showing larger incremental increases than the other two IOUs.

While a good overall indicator of an IOU's total operating costs expected to be recouped in rates, the total SAR is a high-level measure reflecting system costs that does not directly convey the rate and bill impacts of an IOU's bundled customers, who pay for all retail and ancillary services. A trend analysis for **bundled** SAR rather than total SAR better illustrates rate and bill impacts for full-service customers. Bundled SAR can then be broken-down into the bundled residential average rate

[2] Total system cost analysis is based on the total system revenue requirement, as opposed to on a bundled or unbundled customer revenue requirement basis. Bundled customers take generation, distribution, and transmission services. Unbundled customers take distribution and transmission service only.

(RAR), which provides a starting point for defining and measuring affordability for the residential customer class.

A bundled residential customer's total bill is largely driven by the volume of their usage.[3] That volume is reflected in the generation and distribution portions of their bill. However, even though the average residential usage in California is low compared to that of the United States, low usage is showing diminishing returns as a mitigating factor and may no longer be enough to limit customer bill impacts. This is due to the rising bundled RAR and SAR. Furthermore, increases in total or bundled SAR may be attributed to either a rise in IOU revenue requirements, a decline in kWh sales, or both.[4] The main contributors to the rise in IOU revenue requirements in recent years include:

- Capital costs related to infrastructure upgrades;
- Generation purchased power costs;
- Distribution operations and maintenance costs;
- Costs for security and safety enhancements to the grid;
- Costs for contracts with generators to meet resource adequacy requirements; and
- Legislative and regulatory mandates that prioritize environmental and climate goals as essential investments in California's clean energy future.

IOU investments that support wider deployment of zero-carbon and grid modernization resources sometimes carry high price tags despite their potential longer-term benefits for ratepayers. Although substantial investment in transportation electrification and battery storage projects will continue driving SAR increases in 2019 to varying degrees for each of the three IOUs, the anticipated growth in electric vehicles has the potential to increase utility load, thus increasing kWh sales and lowering SAR. Battery storage projects, particularly those with extended contract terms, are also expected to yield cost savings over the longer term.

Due in part to initiatives aimed at creating a low or zero-carbon grid, total system sales have flattened for PG&E, SCE, and SDG&E. These trends in total system kWh sales are driven by the fast-growing number of roof-top solar customers in California and increasing energy efficiency. As a result of these trends, retail rates have the potential to rise more rapidly, especially when revenue requirements increase simultaneously. In addition, this means there are fewer kWh sales over which to spread fixed costs.

This flattened sales demand is reflected in the California Energy Commission's California Energy Demand (CED) managed sales forecasts which show flat mid-demand level managed sales forecasts for all three IOU planning areas projected through 2030.[5] For the purposes of this report, we rely on the CED "managed" sales forecast in lieu of the "baseline" forecast, as the managed sales

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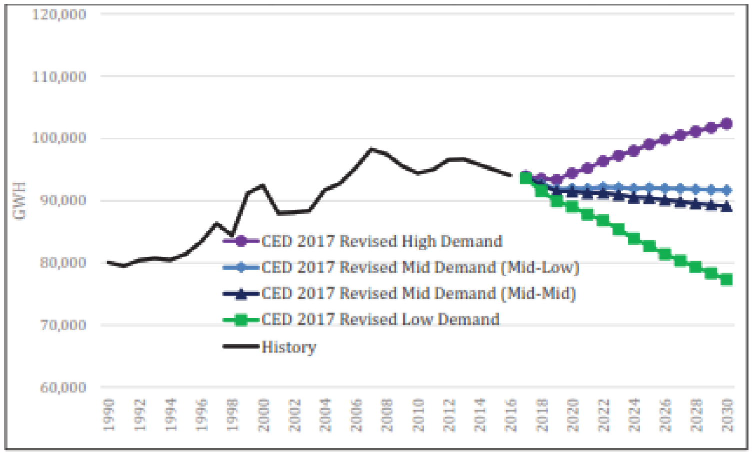
[3] Usage (in kWh) multiplied by a rate factor equals the volume of electricity billed. Whereas the term "usage" s generally used in customer billings, the term "sales" is generally used when discussing SAR.

[4] Revenue requirement and kWh sales are calculated on a forecast basis.

[5] This "managed" sales forecast is an alternative to the CEC's "baseline" sales forecast, which does not include Additionally Achievable Energy Efficiency (AAEE), Additional SB 350 Energy Efficiency, and Additional Achievable Photovoltaic (AAPV).

forecast presents a more conservative set of assumptions. The CED projected managed sales for the PG&E planning area are shown in Figure 1.[6]



Source: California Energy Commission, Energy Assessments Division, 2017.

Figure 1: California Energy Demand Managed Sales, PG&E Planning Area (2017)

Improving cost containment in a competitive energy industry has no singular, one-size-fits-all solution: continually increasing electric utility revenue requirements, decreasing kWh sales, and expanding mandates all make cost control a challenging task. Electric total system average rates increased annually from 2012 to 2019 on average approximately:

- 2% for PG&E;
- 2% for SCE; and
- 6% for SDG&E.

These average annual SAR increases, especially in the case of SDG&E, underscore the need for transparency between operating and infrastructure investment costs, and the costs of policies and programs that keep California's grid green, safe, and reliable. SDG&E has a smaller customer base than the other two IOUs over which to spread those costs, reducing economies of scale for large investments. In addition, SDG&E has an increasing share of customers investing in roof-top solar. These are among the key factors driving SDG&E's SAR upward along a sharper trajectory than SCE or PG&E.

Electric costs and rate trends for bundled customers are highlighted in this report. However, the trends for unbundled customers are similar. Unbundled customers pay for public purpose program (PPP) costs and other costs through electric delivery charges, which are a component of their rates. In addition, through the Power Cost Indifference Adjustment (PCIA) charge, unbundled customers pay for prior commitments made by the IOUs for generation based on long-term forecasts of how much electricity their customers require. This means that some trends discussed in this report are

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[6] *See* California Energy Commission (CEC) California Energy Demand 2018 – 2030 Revised Forecast (February 2018). The PG&E planning area includes total system sales for PG&E and for other utilities in the PG&E planning area. The CEC report indicates that a planning area is closely based on California's balancing authority areas.

the same for unbundled customers and bundled customers: as electric utility transmission and distribution revenue requirements increase and legislative mandates expand, cost and rate control become more challenging for all customers.

Natural Gas Costs

Procurement costs for residential (often referred to as "core") gas customers are recovered in utility gas procurement rates which are adjusted monthly and have fluctuated in recent years relative to electric costs. For 2019, natural gas utility revenue requirements for PG&E, SDG&E and Southern California Gas (SoCalGas) increased over 2018 by 3%, 18%, and 16%, respectively.[7] The principal reasons for these increases are primarily the collection of costs associated with the greenhouse gas emissions reduction program and safety related programs, including new state and federal regulations, to maintain or enhance the safety of gas pipelines.

Vision and Organization of the Report

This report will focus on the causes of California's increasing rates by breaking them down by their underlying costs-to-serve as well as the costs of policy mandates. In addition, the report provides a deeper dive into rate and bill impacts to bundled, full-service IOU customers, with emphasis on the effect of these impacts on affordability for the residential customer class and the following objectives in mind:

- Understanding underlying program and policy drivers of rate trends in California;
- Illustrating how incremental rate and bill impacts may affect IOU customers; and
- Setting forth a vision for how to improve analysis of policy mandates as a tool for decision makers in evaluating the impacts of proposed costs.

With these overarching goals in mind, this report is organized as follows:

- **Section 2**: General trends in electric rates;
- **Section 3**: Legislative program costs;
- **Section 4**: Wildfire Mitigation Plans submitted by the IOUs; and
- **Section 5**: Natural gas cost trends.

Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b)[8] is provided in Appendix A.

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[7] PG&E's revenue requirement is lower than SDG&E and SoCalGas for two reasons: (1) PG&E began implementation of its Pipeline Safety Enhancement Plan (D.12-12-030) and expanded its Transmission Integrity Management Program prior to SoCalGas and SDG&E as a result of the San Bruno gas pipeline explosion, and (2) the Commission in D.16-12-010 partially mitigated the increase for PG&E residential customers by requiring the utility's shareholders fund various safety-related projects as compensation for the San Bruno gas pipeline explosion.

[8] Public Utilities Code Section 913.1(b) states, "In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000

A Lexicon of Key Ratemaking Terms and Definitions

The following is a list of essential definitions used in this document and in the Commission's ratesetting work in GRC Phase I and GRC Phase II proceedings:

- **Bundled Customer:** Refers to customers who get all generation, transmission, and distribution services provided by one entity for a single charge. This will include ancillary and retail services.

- **Bundled System Average Rate:** Bundled authorized revenue requirement divided by bundled kilowatt-hour (kWh) sales.

- **Coincident Demand Charge (CD):** Or peak-related demand charge is a type of Demand Charge that is assessed on the customer's maximum demand in any 15-minute interval during the peak TOU period.

- **Cost of Service Regulation (COSR):** A form of regulation by which the revenue requirement is authorized to reflect the total amount that must be collected in rates for a utility to recover its costs and earn a reasonable return. This type of regulation is sometimes criticized for not providing strong incentives for cost containment.

- **Demand Charge (DC):** A charge (in $/kW) based on a customer's highest moment of electricity usage in a month, other was known as his or her peak demand. A demand charge is assessed on some customers on top of the volumetric charge for total energy usage and is intended to recover the fixed cost of serving that peak load.

- **Distributed Energy Resources (DER):** Distribution-connected generation resources, including energy efficiency, storage, electric vehicles, and demand response technologies.

- **Energy Burden:** Actual home energy costs as a percentage of household income.

- **Fixed Charge (FC):** A charge assessed on customer bills to recover fixed costs.

- **Load Serving Entities (LSE):** A company or organization that supplies load (electricity) to customers.

- **Non-coincident Demand Charge (NCD):** Demand Charge assessed on the customer's maximum demand in any 15-minute interval during the billing cycle.

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or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases."

- **Non-Rate Base Expenses:** Costs that the utility collects from customers but does not place in rate base and for which it does not earn a profit. This includes pass through costs for non-utility owned generation and fuel costs.

- **Non-Wires Alternatives (NWA):** Non-traditional solutions, such as DERs, which replace traditional transmission and distribution investments, such as poles, wires, and transformers.

- **Rate Base:** The book value, after depreciation, of the generation, distribution and transmission infrastructure assets owned and operated by the utility for which they may earn a profit. Other things being equal, a larger rate base results in higher net income for utilities.

- **Rate of Return (ROR) on Rate Base:** The cost of paying back utility debtholders with interest, plus the Return on Equity (ROE) to shareholders, as a weighted average of all types of capital.

- **Return on Equity (ROE):** Return to utility shareholders, or profit, and the most controversial component of the ROR formula.

- **Retail Rates:** Determined by dividing total revenue requirement by total kWh sales (System Average Rate) which is further subdivided by bundled and unbundled customer groups (e.g. bundled system average rates) and by customer class (e.g. bundled residential average rates).

- **Revenue Requirement or Utility Costs:** Total operating costs, depreciation, and a reasonable profit, as recovered in rates.

- **Total Revenue Requirement:** Rate Base x Authorized Rate of Return + Expenses.

- **Total System Average Rate:** Total authorized revenue requirement divided by total kilowatt-hour sales.

- **Unbundled Customer**: Customers who separate the total process of electric power service from generation to metering into its component parts for the purpose of separate pricing or service offering. The term is usually used for CCA or Direct Access (DA) customers.

- **Utility Earnings (or Earning Per Share):** Earnings per share (EPS) represents the portion of a utility's earnings, net of taxes and preferred stock dividends, that is allocated to each share of common stock. The figure can be calculated by dividing net income earned quarterly by the total number of shares outstanding during the same term.

2. Revenue Requirement Trends

Trends in Electric System Average Rate

In Cost of Service regulation, the regulator determines the total amount of money that must be collected in rates for the utility to recover its reasonable and necessary costs plus earn a reasonable profit. The Cost of Service regulatory model aims to provide universal safe and reliable electricity while ensuring that monopoly service providers charge a fair price. Total SAR -- an IOU's total authorized revenue requirement divided by total kWh sales -- is a metric used to measure its cost to serve energy to its customers. Consideration of actions to be taken to limit utility costs should begin with an examination of total SAR in order to see overall trends in an IOU's total costs expected to be recouped in rates to customers. However, SAR alone is not a good metric for determining whether energy bills are affordable.

Historically, the total SAR of each of the three major electric IOUs have increased commensurately. However, starting in 2013, SDG&E's total SAR started showing larger incremental increases than the total SARs of the other two IOUs. Figure 2 shows the total SAR of each of the three major electric IOUs.[9]

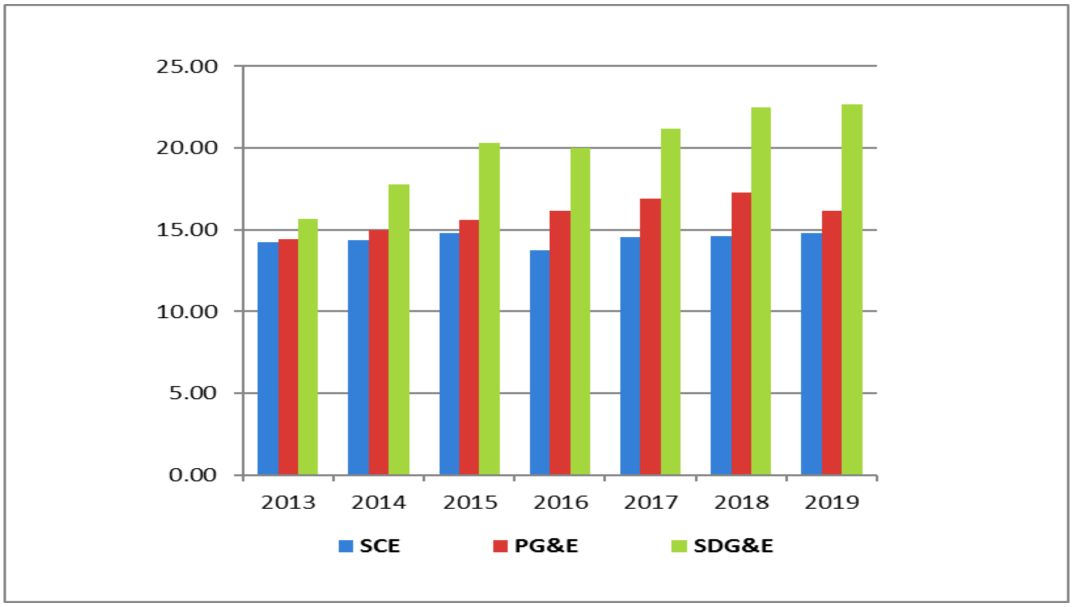

Figure 2: Total System Average Rate (SAR) (¢/kWh)

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[9] In 2019, SCE's electric total system average rate was 14.79¢/kWh, PG&E's was 16.16 ¢/kWh, and SDG&E's was 22.66 ¢/kWh. These figures are based on the January 1 authorized revenue requirement including amortizations of balancing and/or memorandum accounts, and forecasted sales. The January 1 authorized revenue requirement of SCE and PG&E do not include each's 2019 ERRA proceeding revenue requirement, as this proceeding was pending authorization on January 1.

The total SAR of each of the three IOUs had also historically roughly tracked inflation in a gradual upward trend until 2013. For the period 2013 – 2018, the annual percentage change of the total SARs of each of the three major electric IOUs has been generally trending above the annual inflation rate, with SDG&E's total SAR increasing markedly at a faster rate than inflation.[10] Figures 3, 4, and 5 show theoretical annual inflation-adjusted SAR compared to authorized total SAR for each of the three IOUs.[11]

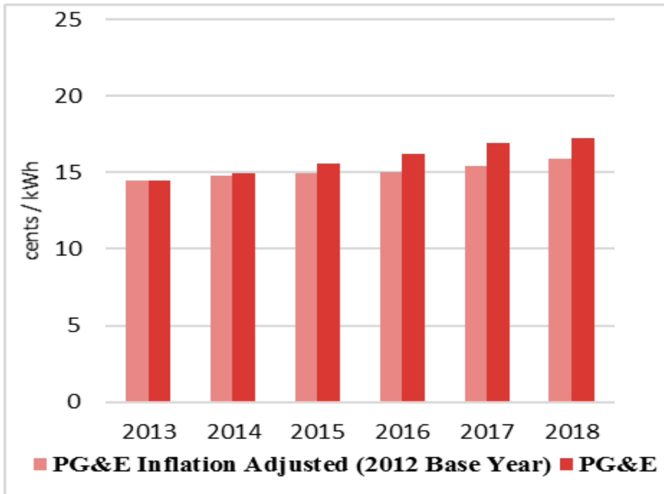

Figure 3: PG&E SAR Comparison: Annual Inflation Adjusted SAR vs. Authorized SAR

[10] Inflation as measured by the Consumer Price Index (CPI) reported by the U.S. Department of Labor, Bureau of Labor Statistics, West, All Items, All Urban Consumers (not seasonally adjusted). Inflation rate is applied to previous year's SAR to show inflation-adjusted SAR.

[11] Electric total system average rates increased annually from 2013 to 2018 by approximately 2% for SCE, 3% for PG&E, and approximately 7% for SDG&E, compared to an average annual inflation rate of 1.9% over the same period (base year 2012).

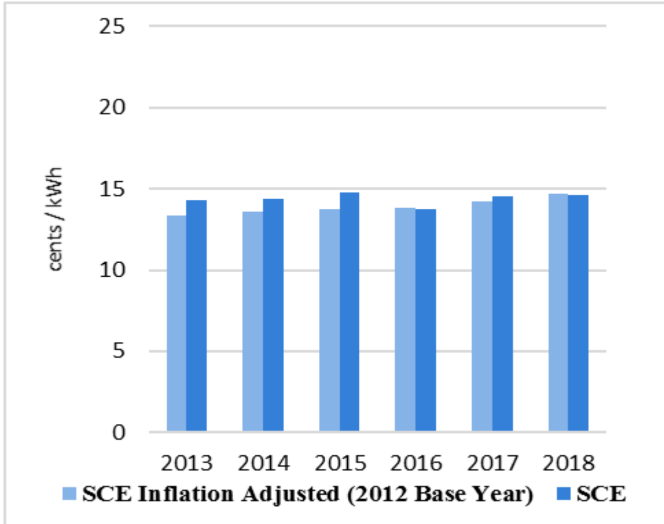

Figure 4: SCE SAR Comparison: Annual Inflation Adjusted SAR vs. Authorized SAR

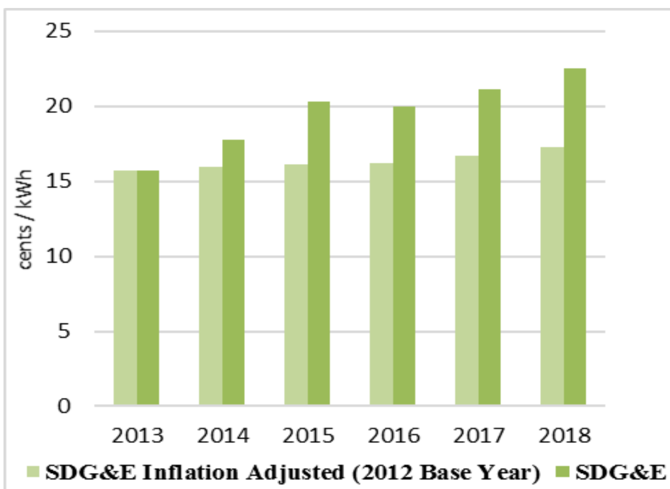

Figure 5: SDG&E SAR Comparison: Annual Inflation Adjusted SAR vs. Authorized SAR

Total SAR does not directly convey rate and bill impacts of an IOU's bundled customers, who pay for all retail and ancillary services. Bundled SAR trend analysis is a framework for illustrating rate and bill impacts for these full-service customers. Bundled SAR can then be broken-down into bundled residential average rate (RAR), the analysis of which provides a starting point for defining and measuring affordability for the residential customer class. Bundled RAR is the rate resulting from the bundled residential customer class' share of the total revenue requirement, based on bundled residential customer class' forecasted sales. Residential tariffs are then designed to collect the revenue requirement reflected in bundled RAR.

Since bundled customers pay for generation service from the utility, and unbundled customers pay for generation from another Load Serving Entity (LSE), bundled customer SAR will necessarily be higher than total SAR which reflects service to all customers. The class average rate is higher than the SAR when the rate class in question contributes to a higher proportion of costs relative to the system average and to other classes. The additive result on bundled RAR of these effects is illustrated in Figure 6.[12]

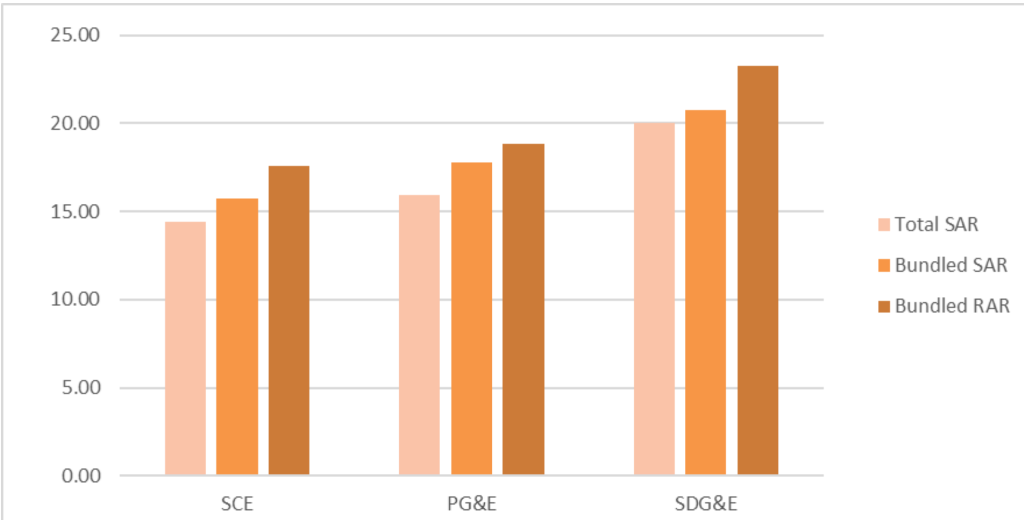

Figure 6: 2013 – 2019 Average Rates (¢/kWh)

In order to dive deeper into affordability issues for the bundled residential customer class, the impact of bundled RARs should be translated into average bills for the bundled residential customer class. The following equation shows how rates translate into bill impacts:

Rate Factor ($/kWh) x Electricity Usage (kWh) = Electricity Billed ($)

Electricity usage is thus a major determinant in calculating supply and delivery bill impacts for bundled residential customers. Historically, while California SARs have been higher than most of the nation, bills have been lower due to the fact that usage in California is low compared to most of the United States. However, low usage may no longer be counteracting the overall rate impacts. From 2013 to 2017, as compared to all United States customers, California:[13]

- Ranked in the 1st (lowest) decile in the United States for average residential electricity usage;
- Ranked in the 9th decile in the United States for average residential rates; and
- Is moving between the 2nd and 3rd deciles for average residential electricity bills.

[12] *See* SCE AL 3896-E-A, PG&E AL 5444-E, and SDG&E AL 3326-E.

[13] U.S. Energy Information Administration (U.S. EIA), 2017, Tale 5A "Average Monthly Bill by Census Division and State," Residential, California and All U.S. The most-recently available year for which data is available is 2017.

Since electricity bills provide a better metric for affordability than rates, a comparison of average bills as a percentage of average income is a next step in looking at electricity affordability. Average electricity bills along with average monthly household income express a ratio of a household's electricity bills to its reported income called electricity burden, as shown in the equation below:

Average electricity bill / Average monthly household income = Electricity Burden

Table 1 shows electricity burden for the three major electric IOUs, for the average bundled residential customer class, based on average household income.

IOU	Average Rate ($/kWh)[14]	Average Monthly Usage (kWh)[15]	Average Monthly Electricity Bill ($)	Average Monthly Household Income ($)[16]	Electricity Burden
SCE	0.16599	554	92	5,699	1.6%
PG&E	0.21182	521	110	5,827	1.9%
SDG&E[17]	0.22086	428	95	6,741	1.4%

Table 1: Electricity Burden, Average Bundled Residential Customers (2017)

The average bundled residential customer in California has an electricity burden of 1.9%.[18] However, the usefulness of this data is limited to high-level benchmarking analysis only, as there are limitations to using average rates and customer electricity usage due to the smoothing effects of using average (mean) data, particularly with large datasets. Similarly, granular low-income customer data in the IOU data reflected in Table 1 is masked by the averaging effect. Further research into affordability should consider electricity burden in the context of low-income customer groups.

Electricity burden, in and of itself, still does not comprehensively define affordability, as it can be affected by other factors such as customer behavioral patterns, housing stock, etc. Electricity burden should also be considered along with other household energy consumption, such as natural gas, to assess overall energy affordability. Traditional metrics for low-income energy research nationwide tend to focus on energy burden, while California studies have also explored a metric

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[14] U.S. EIA, 2017, California Electricity Data, Retail Sales, Total Electric Industry, Bundled Residential. The most-recently available year for which data is available is 2017.

[15] *Ibid.*

[16] U.S. Census Bureau, 2017, median household income based on zip codes in each IOU service territory. Median values were averaged to obtain average household income. U.S. Census Bureau reports household income before taxes. No tax adjustment has been made to the figures in Table 1.

[17] SDG&E residential rates have increased substantially since 2017. The bundled residential average rate effective January 1, 2019 is $0.26251/kWh, which results in an electricity bill of $112 and an electricity burden of 1.7% in Table 1.

[18] California Average Rate $0.18154/kWh; U.S. Average Monthly Usage 560 kWh; Average Monthly Electricity Bill $102; California Average Monthly Household Income $5,315. (Same data sources as for Table 1.)

called energy insecurity, which is characterized as self-reported challenges households face in paying energy bills and compromises they make in affording needed in-home energy costs.[19]

An Order Instituting Rulemaking (OIR) on Affordability, opened July 2018, is developing a framework and principles to assess the affordability impacts of utility rate requests and Commission proceedings. The OIR is examining various metrics to measure affordability, including household-level metrics that could be used to support the decision-making process.[20] While the most common metric to assess the financial impact of utility service on an individual household is energy burden, another household metric that may be considered during the Affordability OIR is residual income, which is a measure of the income that is left over after paying utility bills. Other metrics and data that may be considered during the proceeding are from the 2016 Low Income Needs Assessment Report (LINA) and measure various combinations of resources used to cover household living expenses.[21] Figure 7 shows 2016 LINA Report data regarding conventional and modified energy burden by income group.[22]

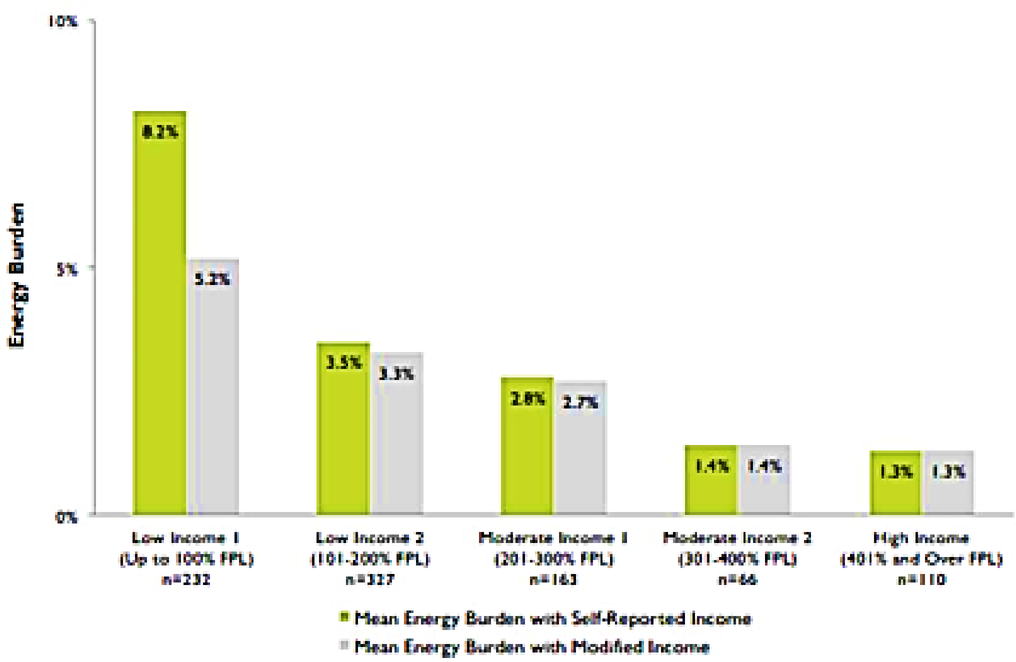

Figure 7: Conventional and Modified Energy Burden by Income Group

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[19] Evergreen Economics, *Needs Assessment for the Energy Savings Assistance and the California Alternate Rates for Energy Programs*, Final Report, Volume 1 of 2, December 15, 2016, p. 47.

[20] *See* R.18-07-006 docket.

[21] The 2016 Low Income Needs Assessment Final Report is available at: http://www.cpuc.ca.gov/iqap/ .

[22] Modified energy burden measures actual home energy costs plus valuation of medical, housing, and food stamp assistance as a
percentage of self-reported gross household income.

Customer bills can be reduced, and energy burden lowered, by reducing usage of both electricity and gas. For electricity customers, reduced usage can result from energy efficiency measures and also from customer self-generation, primarily from rooftop solar installations. Focusing specifically on reduced electricity usage (i.e. not including gas), the California Energy Commission's CED managed sales forecasts show flat mid-demand level managed sales forecasts for all three IOUs projected through 2030.[23] However, as discussed elsewhere in this report, while these reductions in sales can help reduce the bills of the customers and can lower their usage but can also result in increases in SAR rates which could result in bill increases for other customers. Figures 8, 9, and 10 show the CEC managed sales forecasts for each of the major electric IOUs:

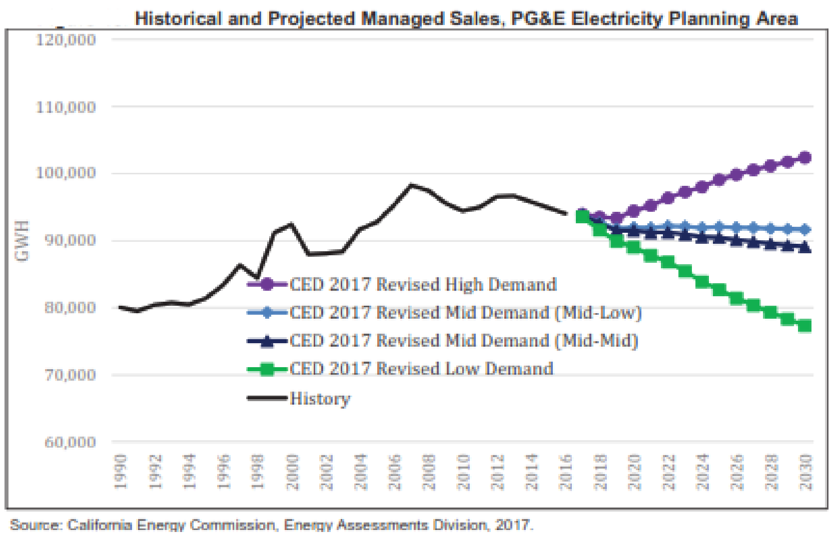

Figure 8: PG&E Projected Managed Sales

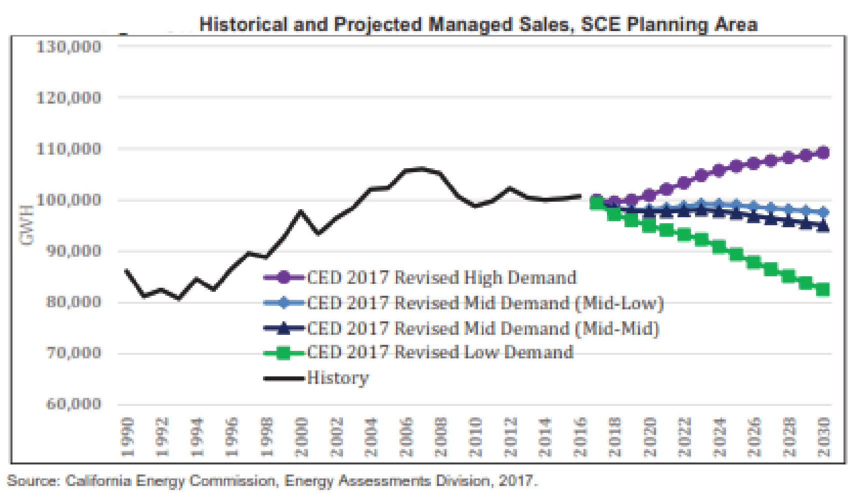

Figure 9: SCE Projected Managed Sales

[23] Managed sales forecasts remove from baseline forecasts additional achievable energy efficiency savings, additional efficiency savings estimated in support of SB 350, and additional achievable photovoltaic adoptions.

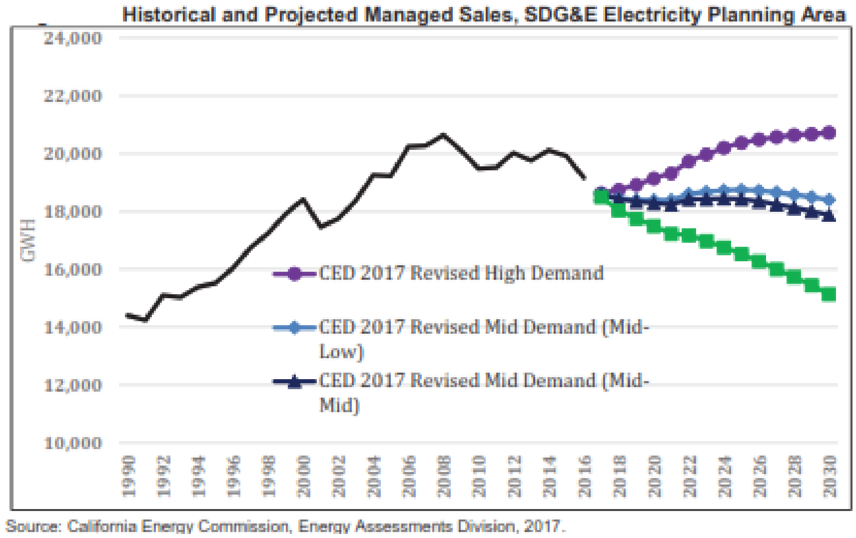

Figure 10: SDG&E Projected Managed Sales

Trends in Electric Revenue Requirements

Cost Recovery

Utilities file detailed descriptions of the costs of providing service (commonly referred to as "revenue requirements") and request authorization of these costs in various rate-making proceedings. Utilities may periodically also be directed by the Commission to file applications pursuant to legislative mandates. For example, applications have been filed in the last several years for program investments and market structures to support wider deployment of zero-carbon and grid modernization, and as a result, substantial costs have been recently authorized in proceedings for transportation electrification and energy storage. In its authorization of an IOU's electric revenue requirement, the CPUC strives to provide electric utility customers safe, reliable utility service and infrastructure, with a commitment to environmental enhancement and a healthy California economy.[24]

Trends in Revenue Requirements by Rate Component

Rate charges appear on customer bills as separate line items. The grouping of rates into generation, distribution, and transmission is primarily based on the costs of each of these functional areas of

[24] More detailed descriptions of how General Rate Case (GRC) proceedings and Energy Resource Recovery Account (ERRA) proceedings authorize utility revenue requirements can be found in the 2018 AB 67 Report (filed April 2019), available on the CPUC website (http://www.cpuc.ca.gov/General.aspx?id=6442460031). All dollars not adjusted for inflation unless otherwise indicated.

utility business. In addition, the distribution rate component includes non-by-passable costs of public purpose programs that are paid by all customers who use the utility distribution system.

The generation rate component covers generation portfolio costs which include the cost of Utility Owned Generation (UOG) consisting of fuel, Operations and Maintenance (O&M) and capital-related revenue requirements associated with generation plants such as nuclear, gas, and hydro. IOUs also recover "purchased power costs" which represent the costs of electricity from third party generators. The impact of renewable contracts to meet the Renewables Portfolio Standard and Greenhouse Gas costs will also be reflected in generation rates.

The distribution rate component covers distribution O&M costs and capital-related revenue requirement associated with distribution infrastructure. This charge reflects the costs to distribute power to customers and includes power lines, poles, transformers, repair crews and emergency services. In addition, the Commission has authorized the IOUs to recover funding related to specific public policy objectives such as transportation electrification and demand response.[25]

The transmission rate component covers all costs associated with the bulk transmission lines owned by the utilities. The transmission rates are set by The Federal Energy Regulatory Commission (FERC).- It is comprised of four sub-components: 1) Base Transmission which recovers the O&M and capital-related revenue requirement associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 4) Transmission Access Charge which reflects the net contribution by IOU customers to the transmission revenue requirements of all participating transmission.

The Public Purpose Program (PPP) rate component covers program funding authorized by the Commission for Energy Efficiency, Low-Income programs, and other public policy programs

Nuclear decommissioning costs are recovered separately in the nuclear decommissioning rate component. Finally, there are costs included in the total revenue requirement that are outside of the IOUs' control such as the DWR Power and Bond Charge revenue requirements which are recovered on behalf of the California Department of Water Resources (DWR). The DWR Power and Bond Charge revenue requirements are recovered on behalf of the California Department of Water Resources (DWR).

[25] Distribution and New System Generation (NSG) charges may be combined for presentation on customer bills. NSG charges recover the costs of "new generation" assets that the Commission has required the IOUs to procure in order to maintain system reliability for the benefit of all customers. The Competition Transition Charge (CTC) may also be shown as a charge on customer bills. The CTC recovers above-market costs resulting from electric industry restructuring pursuant to Public Utilities Code Section 367(a).

The figures below for PGE, SCE, and SDG&E reflect the authorized revenue requirement by rate component forecast on January 1 of each year.[26]

PG&E Revenue Requirement by Rate Component

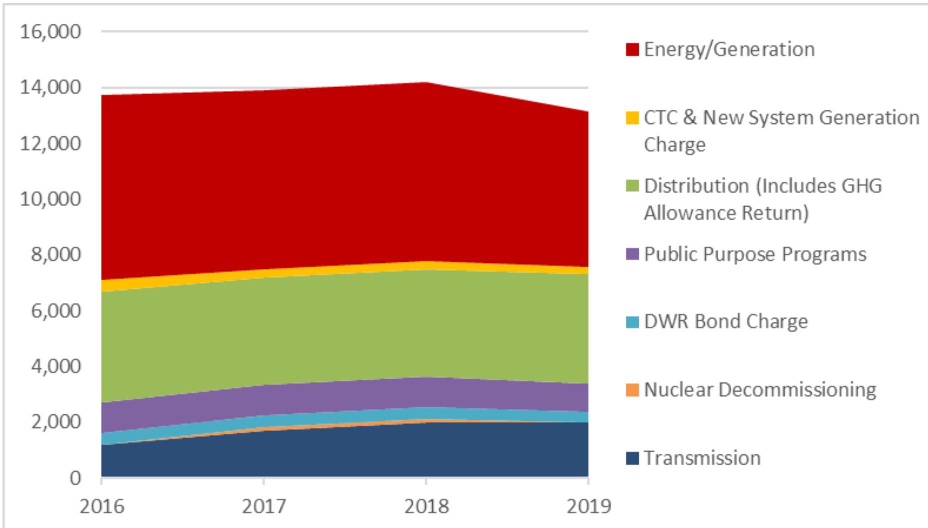

Figure 11: PG&E Revenue Requirement, by Rate Component Category

PG&E's revenue requirement corresponding to costs recovered in its generation rate component has been decreasing over the last several years, while costs recovered in the transmission rate component have significantly increased and costs recovered in other rate components have stayed roughly constant.

The 16% decline in PG&E's generation revenue requirement since 2016 reflects the reduction in PG&E's overall procurement due to lower bundled load over the period 2016 – 2019.

Since 2016, PG&E's transmission revenue requirement has risen 67% with the main cost driver stemming from higher Transmission Owner (TO) revenue requirements due to substantial additions and replacements of PG&E's transmission system. The CPUC is in the process of examining the reasonableness and timing of such proposed transmission projects on a going forward basis.

[26] All data is from 2016 – 2019 IOU responses to Energy Division SB 695 Report data requests. The 2019 Energy Resource Recovery Account (ERRA) applications for SCE and PG&E were pending authorization on January 1, 2019 and are not included.

SCE Revenue Requirement by Rate Component

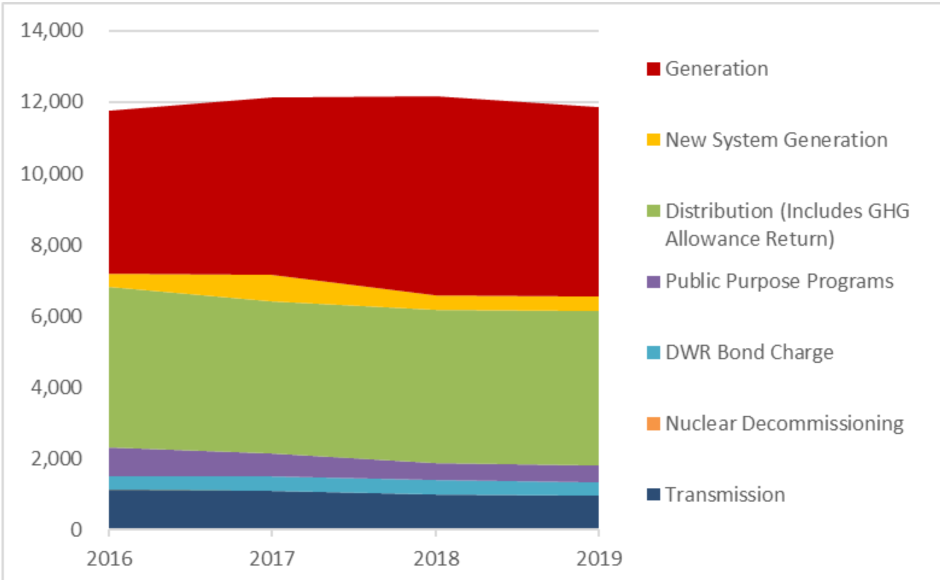

Figure 12: SCE Revenue Requirement, by Rate Component Category

The revenue requirement corresponding to costs recovered in SCE's generation rate component has been rising over the last several years, while costs recovered in other rate components have been trending downward.

SCE's generation revenue requirement has risen about 17% since 2016. Although SCE requests funding to procure enough power to meet its customers' load, there are procurement cost components that are driven by market forces outside of SCE's control, such as natural gas prices. In 2018, a summer spike in natural gas prices significantly impacted electric generation rates. The unanticipated spike lead to a 1.2 cent increase in SAR for ratepayers.[27] The gas price spike in Southern California was due to unprecedented pipeline infrastructure outages and regulatory restrictions on usage of the Aliso Canyon storage fields.

While the distribution revenue requirement has decreased about 4% since 2016 and the transmission revenue requirement has decrease about 18% over the same period, both the distribution and transmission revenue requirements are expected to grow over the coming years as SCE responds to higher wildfire risks. Further, distribution infrastructure costs may rise in connection with the need for a modernized grid that can monitor and control the two-way flow of power in the distribution

[27] See D.19-01-045 (Decision Granting SCE's ERRA Trigger Application (A.)18-11-009) and SCE's AL 3954-E (Implementation of SCE's ERRA Trigger Application in compliance with D.19-01-045). The Commission utilizes reporting mechanisms such as the ERRA trigger in an effort to maintain stability in rates. A second phase of the A.18-11-009 proceeding will consider any penalties for SCE's failure to comply with the Commission's ERRA trigger mechanism requirements.

system will be critical to maintaining, and hopefully enhancing the reliability and resiliency of the grid.

SDG&E Revenue Requirement by Rate Component[28]

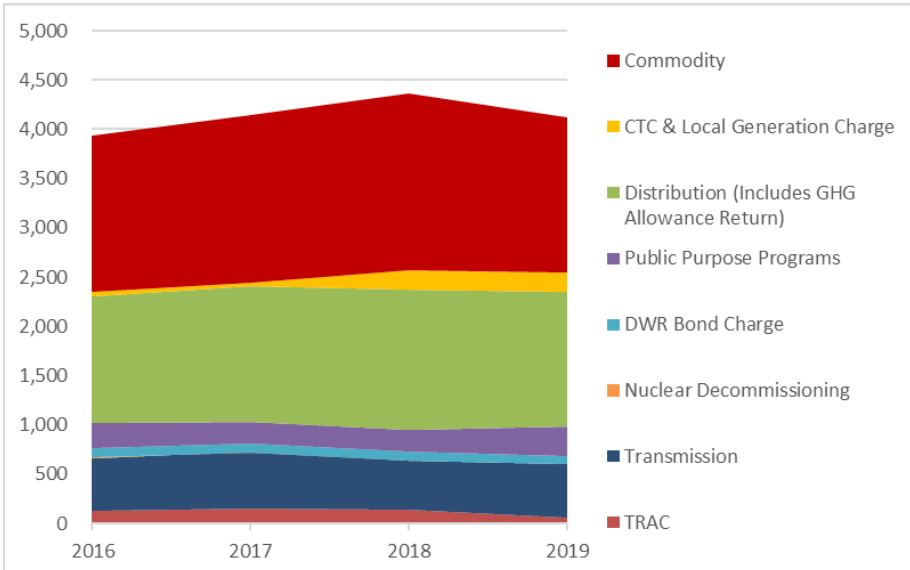

Figure 13: SDG&E Revenue Requirement, by Rate Component Category

SDG&E's generation revenue requirement rose from 2016 through 2018 and then decreased in 2019. The primary drivers of the 12% decrease in generation revenue requirements from 2018 to 2019 are the decommissioning of the San Onofre Nuclear Generating Station (SONGS) and expiring contracts for purchased power.

While the transmission revenue requirement has decreased slightly since 2016, the distribution revenue requirement has increased about 6% over the same period, primarily from higher distribution revenue requirements in SDG&E's 2016 General Rate Case (GRC) than in SDG&E's previous GRC. The 2016 revenue requirement reflects costs approved in SDG&E's 2012 GRC as the Test Year 2016 GRC proceeding was not approved until mid-year 2016. Similarly, the 2019 revenue requirement reflects costs approved in SDG&E's 2016 GRC as the Test Year 2019 GRC proceeding has not yet been approved. The distribution revenue requirement increase is due to increases in O&M for electric distribution and information technology (IT), which is offset by other O&M decreases from escalation, reassignments and FERC allocation costs. Capital related costs

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[28] SDG&E's revenue requirement includes Total Rate Adjustment Component (TRAC), a charge which reflects the cost shift that results from capped residential tiered rates previously legislated under Assembly Bill 1X and Senate Bill 695. The TRAC revenue requirements in Figure 11 reflect an under-collection due to a timing issue resulting from costs shifts not yet fully recovered.

(depreciation, tax, and return) also increased, partially driven by an increase in electric distribution capital expenditures between rate case cycles.

Trends in Revenue Requirement by Proceeding

CPUC-jurisdictional revenue requirements corresponding to the regulated operations of IOUs are authorized in ratemaking proceedings known as General Rate Cases (GRC) on a three-year cycle.[29] The CPUC also approves the level of capital expenditure for generation and distribution assets on a forecast basis for each IOU in GRC proceedings.[30] The utilities earn a rate of return, or profit, only on capital expenditures (e.g. the value of utility owned generation, transmission and distribution assets). The total value of the utility owned capital is referred to as rate base. Return on rate base is thus a component of a utility's authorized revenue requirement and it represents the profit the utility can return to shareholders.

In addition to GRC proceedings, Energy Resource Recovery Account (ERRA) proceedings take place annually to review each utility's fuel and power purchase forecast. If the Commission determines these costs were reasonable it can pass the costs onto ratepayers as part of the revenue requirement. The utility does not earn any profit on these costs. Periodically, program budgets are approved in specific proceedings outside of the GRC or ERRA proceedings. Lastly, the CPUC is required to allow recovery of all FERC-jurisdictional revenue requirements corresponding to transmission rate cases.

The January 1, 2019 revenue requirement for PG&E ($13.1 billion), SCE ($11.9 billion), and SDG&E ($4.1 billion) are shown by proceeding category in Figure 14.[31]

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[29] The CPUC may disallow an expenditure if it is determined to be unreasonably or imprudently incurred.

[30] Annual results may differ from forecasts. The resulting revenue requirement adjustment resulting from under- or over-collecting the authorized revenue requirement in a prior year is reflected in the consolidated January 1 revenue requirement.

[31] *See* SCE's AL 3896-E-A, PG&E's AL 5444-E, and SDG&E's AL 3326-E. GRC Proceeding category in Figure 8 captures all other Non-ERRA proceeding Operating Costs.

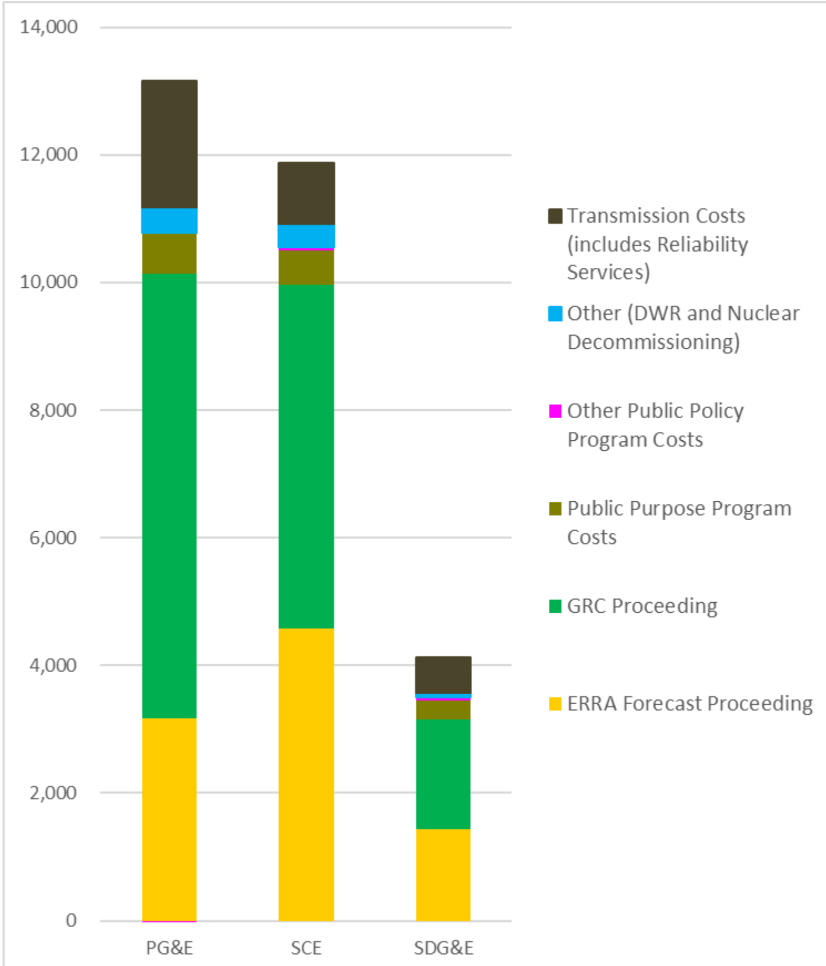

Figure 14: January 1, 2019 Revenue Requirement by Proceeding

The combined ERRA and GRC proceedings comprise about 80% - 85% of each IOU's revenue requirement, with FERC-jurisdictional transmission proceedings comprising approximately 10 - 15% of the total. Public Purpose Programs and Other Public Policy Program Costs[32] are about 5% of the revenue requirement.

Incremental Revenue Requirement Customer Rate and Bill Impacts

As part of evaluating the impact on ratepayers of incremental revenue requirements of costs such as wildfire mitigation plan expense,[33] the CPUC has estimated the 2019 average incremental residential customer rate and monthly bill impacts for customers in PG&E, SCE, and SDG&E's service

[32] Other Public Policy Costs are not collected in the Public Purpose Program rate component and include programs such as the California Solar Initiative.
[33] *See* SB 695 Report section, "Wildfire Mitigation Plans."

territories. The estimated rate impact is based on forecasted data filed by PG&E, SCE, and SDG&E in each IOU's January 1 consolidated revenue requirement advice letter,[34] and the estimated monthly bill impact is based on customer average monthly usage data filed by the IOUs with the U.S. Energy Information Administration (EIA).

The IOUs file consolidated revenue requirement advice letters with effective dates of January 1 to reflect revenue requirements authorized in GRC, ERRA, and other proceedings based on forecasted sales. Rate impacts can be calculated down to customer class by breaking down the revenue requirement by bundled and unbundled customers and then further by customer class, and then dividing by forecasted sales for each bundled or unbundled customer class.

The resulting rate impacts are a high-level estimate of the forecasted cost responsibility of a proposed or authorized incremental revenue requirement at customer class level. Actual cost recovery will depend on the authorized cost recovery mechanism. For example, if cost recovery is authorized through the distribution rate component, bundled residential customers will see a higher incremental rate than that indicated by the overall residential customer class, as the bundled residential customer class contributes a higher percentage share of customer class costs relative to the unbundled residential customer class.[35]

Estimated rate impacts are then multiplied by the actual average usage per customer for bundled and unbundled customer classes to get estimated average bill impacts per customer based on actual

[34] Revenue requirement for SCE and SDG&E by customer class was obtained through data requests.

[35] Bundled residential customer class rates and unbundled residential customer class rates will average to the overall residential customer class rate.

usage. For each IOU, the actual average usage per customer for the bundled and unbundled residential customer class is publicly-available information found on the EIA's website.[36]

Estimated rate and bill impacts presented in this report[37] are based on the following assumptions:

- Incremental revenue requirements correspond to authorized cost recovery that does not take into account the mechanism for subsequent cost recovery;[38]
- Rate and bill impact calculations assume no change in forecasted sales for incremental revenue requirement;
- 2017 actual electricity usage is a proxy for 2019 actual electricity usage; and
- Estimated rate and bill impacts do not take into account any cost savings that may accrue to certain IOU cost categories or customers.[39]

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[36] *See* https://www.eia.gov/ . The latest data available is for 2017.

[37] *See* SB 695 Report section "Legislative Programs" and section "Wildfire Mitigation Plans."

[38] Cost recovery mechanisms may include: 1) authorization of the rate component through which the cost will be recovered; 2) customer class responsibility for cost recovery; and other terms or conditions.

[39] For example, energy efficiency programs show up as a cost under the public-purpose programs, however there should be a corresponding savings in other IOU cost categories and in overall bills due to reduced usage.

3. Legislative Programs: Present and Future Cost Implications

The following legislative programs are grouped into Supply-Side Programs (Renewable Portfolio Standard) and Demand-Side Programs (all others). For select programs for which budget, rate and bill impact information is presented, it is critical to evaluate these numbers with the following disclaimers in mind:

- Residential rate and monthly billing impact information is for illustrative purposes only and based on approximations in budget information for 2019.
- Where annual budget spending is not specified for 2019, approximations were made using levelized spending assumptions across budget years for simplicity, even though such linear spending patterns are unlikely to occur in many cases.
- Capital expenditure assumptions for infrastructure, as in the case of Transportation Electrification (TE) projects and Wildfire Mitigation Plans, reflect capital spend and must be converted to the corresponding revenue requirement before determining rate and bill impacts.[40]

Renewable Portfolio Standard and Integrated Resource Planning

Background and Status

SB 1078 initiated the Renewable Portfolio Standard (RPS) in 2002 establishing targets for eligible renewable energy resources such as wind, solar photovoltaics (PV), hydroelectric, and biomass. The RPS targets have been legislative adjusted several times their current values that now include a 60% eligible renewable target by 2030.[41] The overall contracted commitment in renewables by retail sellers in California has increased over time. California's three large IOUs collectively served 36% of their 2017 retail electricity sales with renewable power.

The CPUC sets cost-effectiveness policies and collects various renewables price data to understand cost trends and the impact of these costs on ratepayers. Figure 15 illustrates the average annual

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[40] Capital is converted to revenue requirement by applying authorized return on rate base and a factor to adjust the return on rate base to a gross revenue requirement. 2019 is considered the first year for converting capital spend to revenue requirement.

[41] On September 10, 2018, SB 100 (de León, 2018) was signed into law, which accelerated the RPS requirement to 60% by December 31, 2030, with interim targets of 44% by December 31, 2024, and 52% by December 31, 2027 and sets a goal that all of the state's electricity to come from carbon-free resources by 2045.

contract prices in their year of execution for procuring RPS eligible projects with capacities greater than 3 MW in cents per kilowatt-hour (¢/kWh) for the three IOUs. [42, 43]

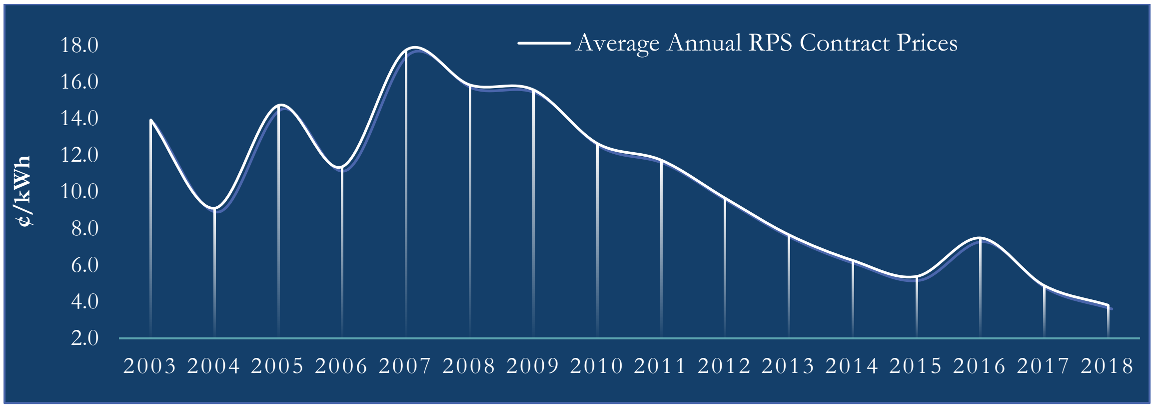

Figure 15: Average Annual RPS Contract Prices by Year of Execution, 2003 - 2018 (Real Dollars)

The IOUs use competitive procurement mechanisms and a least-cost, best-fit evaluation methodology to ensure procurement of renewable resources that provide the most value in their RPS Procurement Plans.

In 2018, RPS procurement expenditures accounted for less than 20% of the IOUs' total revenue requirements and are anticipated to decrease on a ¢/kWh basis slightly as the cost of new RPS projects are expected to decline over time. Further, the share of RPS procurement expenditures to the IOUs' total generation revenue requirement remained proportional to the overall percentage of RPS generation in 2018. In 2019, the expenditures are expected to increase to $5.5 billion due to procuring increased amounts of renewable energy, but as noted above, they are expected to follow the declining trend, on a ¢/kWh basis.

SB 350 requires the Commission to identify an optimal portfolio of resources to achieve California's long-term greenhouse gas (GHG) reduction goals at lowest costs while maintaining reliability and to create a process for all load-serving entities (LSEs) to file individual integrated resource plans (IRPs) with the CPUC. In February 2018, the Commission adopted its first IRP Reference System Portfolio of energy resources to meet a GHG planning target of 42 million metric tons (MMT) by 2030 for the electric sector, which identified a need to procure renewable resources beyond the 50% RPS target as part of a cost-effective portfolio. LSEs submitted integrated resource plans on August 1, 2018,[44] outlining their strategies for meeting their LSE-specific GHG planning targets while achieving the state's other policy goals. The Preferred System Portfolio (PSP) is pending adoption by the

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[42] Contract prices have been adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry.

[43] *See* CPUC's *2019 Padilla Report, Costs and Cost Savings for the RPS Program* for more on historical renewable energy resource contract pricing.

[44] *See D.18-02-018.*

Commission in 2019, which will account for the aggregated IRP filings and any associated policy actions needed to drive procurement and program activity across multiple supply and demand resources.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

In 2019, the CPUC will take steps implement SB 100's accelerated and increased RPS requirements. In addition, efforts for RPS and IRP coordination and alignment will continue as IRP goals and planning requirements overlap with LSEs' exiting RPS obligations. The CPUC will continue to determine and enforce compliance with RPS procurement requirements for all retail electricity sellers in California through the evaluation of the utilities' annual RPS Procurement Plans, outlining long-term RPS forecasts and planning mechanisms.

Energy Storage Programs

Background and Status

In response to AB 2514 (Skinner, 2010), the Commission established IOU energy storage targets of 1,325 MW to be procured by 2020 and operational by 2024. The energy storage must be procured within 3 grid domain sub-targets: behind the meter, distribution connected and transmission connected. The storage is required to be "cost-effective" which has been defined to include least-cost-best-fit (LCBF). What this means is the Commission must procure storage that is cost reasonable. This means that sometimes the storage will increase ratepayer costs and sometimes save ratepayer costs. A future storage evaluation will help the Commission verify how cost effective the storage procurement is as well as how well the storage is achieving state policy goals.

In 2018, the Commission approved 905.5 MW of storage projects. At the Moss Landing Sub Area PG&E procured 567.5 MW of storage that will directly reduce the need for more expensive natural gas contracts and represents the largest battery storage projects approved in the world. This project is expected to save ratepayers $233 million over 10 years and some of the contracts are for 15-20 years so cost savings could be greater. The Commission has also approved procurement of more than 1,600 MW of new storage capacity to be built in the state, of which 410 MWs are online and operational, which is about 26 percent of total approved storage capacity. Collectively, the three major IOUs have exceeded in the 1,325 MW target set in response to AB 2514. At the end of 2018, PG&E and SCE still need addition domain-specific procurement to meet the sub-targets: PG&E requires 39 MW in the customer domain[45] and SCE needs 139 MW in the transmission domain to

[45] The customer domain refers to the customer's side of the meter (also known as behind-the-meter), rather than the utility's side in the distribution grid.

fulfil their respective 580 MW shares of the target. SDG&E met its 165 MW share of that requirement.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

Activities and proceedings that could result in additional energy storage procurement in this period and are expected to either save ratepayer costs, or at worst be cost neutral, include:

- IOU distribution deferral solicitations underway or imminent in the Distributed Resource Planning (DRP) and (Integrated Distributed Energy Resource (IDER) proceedings. If storage is procured as "non-wires alternatives" the cost is expected to be the same or less then the tradition infrastructure projects being deferred.

- SCE application for approval of 200 MW of energy storage contracts to meet the local capacity requirement (LCR) needs in the Moorpark Sub Area, and to satisfy the requirements of SB 801 which directed SCE to deploy energy storage to address Aliso Canyon gas facility operation limitations, In aggregate these projects are expected to provide net positive ratepayer benefits for the 10-20 year contract terms.

- PG&E application for approval of energy storage contracts in the Oakland Clean Energy Initiative (OCEI) to replace retired gas generation and avoid the construction of new transmission lines needed for reliability. If storage is procured as non-wires alternatives the cost is expected to be the same or less than the tradition infrastructure projects being deferred.

- PG&E and SCE are each evaluating large energy storage procurement opportunities as environmentally preferred alternatives to planned distribution substation and transmission upgrade projects for reliability. If storage is procured as non-wires alternatives the cost is expected to be the same or less than the tradition infrastructure projects being deferred.

These activities may result in additional procurement of storage that could either increase or decrease ratepayer costs:

- The IOUs' AB 2868 Applications are pending before the Commission. The proposed projects include distribution connected and behind-the-meter (BTM) storage projects that address the legislative directives. The full cost impact of these projects is under evaluation.

Longer-Term Trends (May 2020 and Beyond)

Since the inception of the CA Storage Procurement Framework the cost of storage procured by the IOUs has dropped 40-50%, and the downward cost trend is continuing. CPUC Staff continue to see lower storage procurement prices as the contracts come in for Commission approval. One of the initial goals of the CPUC storage procurement mandate included market transformation. We are seeing evidence that in some instance's storage provides net savings to ratepayers when it is:

- Procured as a transmission or distribution infrastructure alternative;
- Procured as an alternative to high priced and/or replacement for aging/retired gas plants;
- Procured as a Local Capacity Resource.

The Commission will continue to implement the Multiple-Use Application (MUA)[46] framework to enable storage to provide multiple stacked benefits and services to enhance the value to ratepayers.

Transportation Electrification (TE) Programs

Background and Status

The CPUC and IOUs are responding to several legislative mandates and gubernatorial directives to expand statewide transportation electrification (TE)[47] programs. The IOUs are directed to submit applications with the CPUC to invest in programs that accelerate wide-spread TE, specifically for charging station availability, underserved communities[48], new technologies for customers, and vehicle-to-grid (VGI) integration.[49] These programs are to contribute to California's zero-emission vehicle (ZEV) targets of 5 million ZEVs on the road by 2030, and 250,000 installed publicly available electric vehicle charging stations and 200 publicly available hydrogen fueling stations in the state by 2025.[50] Additionally, the CPUC is taking steps to ensure the IOUs TE infrastructure investments are equitably deployed throughout the state.[51]

The CPUC's policies for EVs continue to focus on three key objectives:

- Accelerate the buildout of EV charging infrastructure
- Establish electric rates that encourage beneficial charging behavior
- Utilize VGI integration technologies that allow EVs to serve as a grid resource, facilitate increase renewable energy usage, and mitigate daily electric load imbalances.

The legislative mandates require using ratepayer funding to address the market barriers that prevent long-term EV charging infrastructure investments. The approved IOU TE infrastructure programs, and those currently under review by the CPUC, seek to identify and overcome specific EV infrastructure deployment obstacles. To manage costs and support the development of the market,

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[47] SB 350 defined TE as any vehicle fueled by electricity generated outside of the vehicle, including light-duty vehicles, medium- and heavy-duty vehicles, off-road vehicles, and shipping vessels.

[48] Such as multi-unit dwellings (MUD), workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.

[49] SB 350.

[50] Executive Order (E.O.) B-48-18

[51] SB 1000.

the CPUC is encouraging competition amongst EV charge network companies, attracting private investment in TE infrastructure, and minimizing costs placed on the ratepayers.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

In 2016, the CPUC approved a total of $197 million for the IOUs' first large TE infrastructure investment programs. The IOUs are in the process of installing the EV charging infrastructure and will continue to collect the revenue requirements through 2021[52], as shown in Table 2, with corresponding rate and bill impacts shown in Table 3.

	SDG&E[53]	SCE[54]	PG&E[55]
Program Timeline	Dec. 2016 - Dec. 2019	April 2016 - April 2018	Jan. 2018 - Jan. 2021
Budget	$45 million	$44 million	$130 million
Remaining Budget	$13.2 million (Sept. 2018)	$24.7 million (Dec. 2018)	$102.2 million (Dec. 2018)
Scope	3,000 charge ports	1,500 charge ports	7,500 charge ports
Ports Installed	932	1,280	594
Market Segments	• Multi-unit Dwellings (40% target) • Workplaces • Disadvantaged Communities	• Multi-unit dwellings (25% target) • Workplaces • Destination centers • Disadvantaged communities (10% target)	• Multi-unit dwellings (20% target) • Workplaces • Disadvantaged communities (15% target)
Ownership	SDG&E	Site Host	Site Host or PG&E[56]

Table 2: IOU Light Duty Infrastructure Pilots

Utility	2019 Cost Allocation for Pilots[57]	2019 Cost Allocation - Capital	2019 Cost Allocation - Expense	2019 Residential Rate Impact	2019 Residential Monthly Bill Impact
PG&E	$34.1 million	$29.3 million	$4.8 million	$0.0001	$0.06
SCE	$24.7 million	$17.5 million	$7.2 million	$0.0001	$0.08
SDG&E	$13.2 million	$7.5 million	$5.7 million	$0.0005	$0.19

Table 3: IOU Light Duty Infrastructure Pilots – 2019 Rate and Bill Impacts

[52] Program timelines are "soft" and may be continued until the budget is expended.
[53] D.16-01-045.
[54] D.16-01-023.
[55] D.16-12-065.
[56] PG&E is allowed to own the infrastructure at multi-unit dwellings and disadvantaged community sites, and has a limit of owning 35% of the total program infrastructure.
[57] For SCE and SDG&E, this assumes the remaining budget will be spent in 2019. For PG&E, assumes that the remaining budget will be spent over three years (2019 – 2021) with levelized 2019 spend.

In 2018, the Commission approved five large programs with a total budget of $738 million for a wider deployment of EV infrastructure programs for residential, commercial, and medium duty/heavy duty vehicles. Small programs were also approved in 2018 with a total budget of $42 million.[58]

The IOUs started to implement the projects listed in Table 4 in 2018. Costs associated with the large programs $738 million budget are expected to be recovered through distribution rates over the period 2019 – 2023, and cost recovery of the small programs $42 million budget is estimated to take place over the period 2018 – 2022. To derive a simple, uniform incremental rate and monthly bill impact for each of these multiyear budgets, we have converted the total capital budget to revenue requirement,[59] added total budget expense, then divided each sum by 5 and have separately calculated the residential rate and monthly bill impacts for 2019, as follows: (1) PG&E: $0.0002 rate increase, or $0.13 per month, (2) SCE: $0.0004 rate increase, or $0.22 per month, (3) SDG&E: $0.0018 rate increase, or $0.77 per month.

Utility	Large Projects Budget[60]	Small Projects Budget[61]	Total Budget	Total Budget - Capital	Total Budget - Expense	2019 Budget (Levelized $)	2019 Residential Rate Impact	2019 Monthly Bill Impact
PG&E	$258,718,701	$7,783,900	$266,502,601	$201,041,626	$65,460,977	$17,533,264	$0.0002	$0.13
SCE	$342,656,222	$15,445,000	$358,101,222	$251,696,550	$106,404,670	$26,803,446	$0.0004	$0.22
SDG&E	$136,905,000	$17,883,867	$154,788,867	$29,356,235	$125,432,632	$25,725,114	$0.0018	$0.77
TOTAL	$738,279,923	$41,112,767	$779,392,690	$482,094,411	$297,298,279			

Table 4: Large IOU Approved Program Budget

The CPUC is currently reviewing nine EV infrastructure proposals and one EV rate proposal that request an additional $930 million in utility investments.

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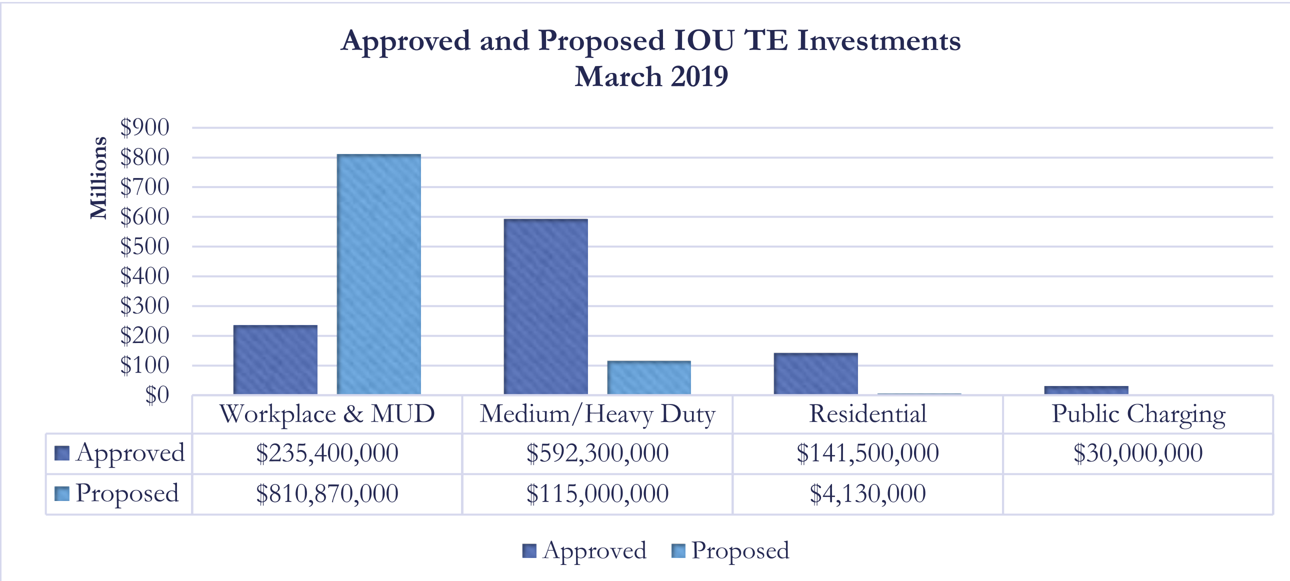
58 Large and small budget figures presented here exclude evaluation costs.

59 O&M expenses directly translate to revenue requirement, however, capital costs reflect capital spend and must be converted to the corresponding revenue requirement. Capital is converted to revenue requirement by applying authorized return on rate base and a factor to adjust the return on rate base to a gross revenue requirement. 2019 is considered the first year for the purposes of converting capital spend to revenue requirement.

60 D. 18-05-040 authorized $738 million for three standard review programs. As established by the September 14, 2016 ACR issued in R.13-11-007, Standard Review Projects are larger programs that do not meet the criteria of Priority Review Projects.

61 D. 18-01-024 authorized $42 million for fifteen priority review programs. An ACR was issued on September 14, 2016 in R.13-11-007 that established Priority Review Projects were to be programs that were non-controversial, and limited to 1-year, $4 million per program, and $20 million total per utility.

If approved, the cost recovery for these programs will likely start in 2020.[62] Figure 16 shows approved and proposed TE program budgets.



	Workplace & MUD	Medium/Heavy Duty	Residential	Public Charging
Approved	$235,400,000	$592,300,000	$141,500,000	$30,000,000
Proposed	$810,870,000	$115,000,000	$4,130,000	

Figure 16: Approved and Proposed Transportation Electrification Budgets

Longer-Term Trends (May 2020 and Beyond)

The IOUs have requested an additional $930 million for charging infrastructure and other transportation electrification program costs. PG&E has requested $4.13 million for a low-moderate income residential charging program, SCE has requested $760.1 million to expand the Charge Ready program to install EV charging infrastructure and provide rebates to support approximately 48,000 charging ports, and SDG&E has requested $115 million to install make-ready infrastructure to medium/heavy duty vehicles. PG&E, SCE, and SDG&E also have applications that request a total of $50.8 million for charging infrastructure, and education and outreach efforts for TE pilots at schools and parks. The total budget of these proposed programs is approximately $930 million, as shown in Table 5.

Utility	Proposed TE Infrastructure Program Budgets
PG&E	$15.43 million
SCE	$779.87 million
SDG&E	$134.7 million
Total	$930.0 million

Table 5: Proposed IOU EV Infrastructure Program Budgets

[62] See Sub-section "Longer-Term Trends (May 2020 and Beyond)" for details on the utility investment proposals totaling $930 million.

The CPUC is also working with the IOUs to design electric rates that support grid beneficial EV charging habits, while preventing cost shifts to ratepayers who don't drive EVs. In 2019, the CPUC will consider how to adopt rates and implement VGI in a way that will enable EV charging to benefit the grid by encouraging charging at times of the day and locations that facilitate the use of low-cost renewable energy. The goal is to enable EVs to communicate with the grid to provide demand response, storage, and VGI services. The CPUC and IOUs are piloting several programs to better understand this technology.

In an effort to address the need for a more focused process to guide utility investments in transportation electrification, the CPUC has opened an Order Instituting Rulemaking (OIR)[63] to streamline the Commissions efforts for future transportation electrification programs, tariffs, and polices. One component of the OIR directs the IOUs to file a new joint rate proposal that will identify the most appropriate rate structures to manage the additional load from ZEV charging and the potential to create value from managed ZEV charging. The IOUs have been directed to identify mechanisms that will make off-peak electricity for refueling cost less than the cost of conventional fuels such as diesel and petroleum, while also promoting customer participation in efforts to better integrate ZEV charging load onto the grid.

The OIR also directs CPUC Energy Division (ED) staff to develop a transportation electrification framework (TEF) which will, amongst other things, define the role of IOU ratepayer funding in meeting the states TE goals. The CPUC will examine pathways to encourage third-party investments and to align IOU investments with other state agencies to lessen the rate impact of TE investments on ratepayers.

While the IOUs have requested ratepayer funds for their TE infrastructure programs, the anticipated growth in EVs has the potential to increase utility load and offset declining kWh sales, particularly in off-peak periods which can reduce rates. EV growth will likely lead to higher overall electricity demand which presents the opportunity to enact dynamic grid management programs such as demand response, storage and VGI services. These programs have the potential to drive down rates for all ratepayers, however, their success depends on a revenue requirement increase to fund the necessary EV programs. It is essential for the CPUC to continue to design policies that ensure the IOUs TE investments are cost-effective, in the best interests of ratepayers, and within the scope of the IOUs responsibilities.

[63] R.18-12-006.

Energy Efficiency (EE) Programs

Background and Status

The CPUC regulates ratepayer-funded[64] energy efficiency (EE) programs managed by the utilities, other program administrators, and vendors. The Commission establishes energy savings goals and energy efficiency program administrators (PAs) submit budgets for programs to achieve those goals.[65] Annual budgets are reviewed by Energy Division staff and collected in rates through the Public Purpose Program (PPP) revenue requirement. In order to ensure these funds are being used effectively, the CPUC evaluates all ratepayer-funded energy efficiency programs for cost-effectiveness and verifies energy savings. In the 2018 program year, the approved energy efficiency program budgets across IOUs were $925 million. In 2018, reported program electricity savings were 3,103 gigawatt-hours and natural gas savings were 77 million therms.[66]

It is important to recognize that while energy efficiency programs have ratepayer costs, they also provide ratepayer benefits in the form of reduced energy consumption and, ultimately, lower customer bills. Generally speaking, as long as energy efficiency programs are cost effective, benefits to customers should always be greater than the costs in rates (and greater than out-of-pocket costs paid by customers for higher-efficiency products, given the CPUC's use of the Total Resource Cost test in assessing EE portfolio cost effectiveness).

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

After the PAs filed their Annual Budget Advice Letters in September 2018, Commission staff authorized $758 million in energy efficiency program spending for 2019. If a utility is not able to contract for all forecasted energy efficiency programs in a given year, unexpended funding rolls over into the next year's budget request, and the tariffs used to collect these funds are reduced accordingly. For 2019, the total authorized budget of $758 million is reduced based on what was "unspent and uncommitted" from 2018 ($11million). In addition, only for 2019, the utilities will true up the "unspent and uncommitted" budget from all previous cycles ($305 million). Therefore, the total utilities will need to collect in 2019 through rates is $453 million.

The reason that the unspent and uncommitted funds balance from pre-2018 years is so high is that the policy of granting incremental funding, where previous years' carry-forward balances are used to offset the current request was instituted relatively recently, in the 2015 program year. With the challenges of launching a new energy efficiency process in 2016, and closing out the previous 2013-2015 cycle, it has taken some time to sort out the carry-forward budgets and ensure they are

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64 These funds are collected as a portion of the public purpose program rate component.

65 In January 2017, program administrators submitted their initial 10-year forward business plans for energy efficiency. The business plans were reviewed and approved by the CPUC in 2018 via D.18-05-041.

66 The 2018 figures report expenditures and savings for the 2018 program year. These figures appear lower than the 2017 report because an 18-month reporting period was used for the 2017 report.

deducted from the incremental budget requests from the PAs each year. The 2019 budget request reflects progress in this endeavor. Table 6 shows IOU energy efficiency budgets and authorized collections for the 2018 and 2019 program year.[67]

IOU Energy Efficiency Budgets, 2018-2019						
	2018		2019		Customer Impact[68]	
Utility	Total Budget	Public Purpose Funding Requirement	Total Budget	Public Purpose Funding Requirement	2019 Residential Rate Impact	2019 Residential Monthly Bill Impact
PG&E	425,185,369	413,644,102	319,511,700	186,491,441	$0.0026	$1.35
SCE	299,637,160	299,637,160	230,173,822	92,891,778	$0.0014	$0.77
SCG	83,703,499	83,703,499	101,961,000	66,798,000	‘--------	‘------
SDG&E	116,456,311	116,456,331	106,665,916	106,665,916	$0.0074	$3.18
Totals[69]	**924,982,339**	**913,441,092**	**758,312,438**	**452,847,135**		

Table 6: 2018 and 2019 Approved Energy Efficiency Budgets and Rate Impacts

Longer-Term Trends (May 2020 and Beyond)

The projected long-term energy efficiency budgets are described in business plan filings by each energy efficiency PA and forecast the spending necessary to meet the Commission established energy savings goals for the same period. Table 7 shows the total of the PAs' budgets are projected to rise from $853,708,071 in 2020 to $880,169,403 in 2024.[70] The projected budget amounts trend slightly upwards, meeting the goal of increasing energy savings while keeping costs down.

	2020	2021	2022	2023	2024
PG&E	354,274,412	355,707,745	356,599,412	355,692,120	355,668,162
SCE	275,649,883	270,600,813	278,583,316	286,805,293	295,273,930
SCG	104,064,000	106,195,000	108,356,000	110,548,000	112,771,000
SDG&E	119,719,776	119,719,776	119,719,776	116,456,311	116,456,311
Total	**853,708,071**	**852,223,334**	**863,258,504**	**869,501,724**	**880,169,403**

Table 7: Projected Energy Efficiency Budgets by IOU

[67] Source: Annual Budget Advice Letters of PG&E, SCE, SCG, and SDG&E, 2018 and 2019.
[68] These customer impacts are the rate and bill impacts of the gross EE budgets before accounting for customer savings / benefits.
[69] Totals include Evaluation, Measurement & Verification funding, Regional Energy Network funding, Community Choice Aggregator funding, and unspent/uncommitted funding.
[70] These are based on projected budgets. In some cases these figures differ from approved budget amounts.

Several factors can affect the long-term projections contained in the PA business plan filings. First, and primarily, the Commission is currently developing an update Energy Efficiency Potential Study, in collaboration with the CEC, which will set the goals for upcoming energy efficiency programs. During 2019, the Potential Study will pass through a stakeholder process for public comment. The results of the study will enable the Commission and PAs to select the most promising options for cost effective energy savings in 2020 and beyond.

Second, energy efficiency PAs are now required to contract with third party implementers for a majority portion of their energy efficiency activities.[71] The rationale for third-party requirements is based on supporting innovation in program design, as well as the potential for cost savings through competitive solicitation of programs. In January 2018, the CPUC increased the required minimum percentage of third-party programs from 20% of total budgeted portfolio by 2020, to at least 25% by the end of 2018, 40% by the end of 2020, and 60% by the end of 2022.[72] These solicitations may, ultimately, bring down overall costs of EE programs and portfolios.

Third, the CPUC has recently put in place new requirements for IOUs to implement certain statewide energy efficiency programs.[73] Statewide programs are designed to deliver energy efficiency programs uniformly throughout the four major IOU service territories. Administering these programs on a statewide basis is intended to reduce transaction costs for administrators and implementers by allowing uniform incentive structures and reduction of administrative burden across IOU service territories. This can reduce costs for ratepayers.

Fourth, in January 2019, the commission clarified the use of normalized metered energy consumption (NMEC) approaches in measurement and verification (M&V) practices for in-house and third-party program implementation, as per AB 802.[74] NMEC may require upfront investment and longer reporting periods but has the potential to capture savings in a more streamlined and accurate way than currently used M&V practices. In the long term this approach may reduce program costs. NMEC can support pay-for-performance programs in which ratepayers only pay for energy efficiency savings that is documented by metered data.

Finally, the Commission is also considering initiatives for a new California market transformation framework intended to enable utilities and third parties to develop innovative ways to capture energy savings that may have been missed so far, to remove barriers to energy savings, and to move emerging technologies and measures down the pathway toward adoption and eventually into code. The goal is to improve cost effectiveness of energy savings through innovative new approaches and to find new ways to save energy.

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71 *See* http://www.cpuc.ca.gov/General.aspx?id=4460 .

72 D.18-01-004.

73 D.16-08-091, with later revisions in D.18-05-041.

74 A.17-01-013, Ruling on Certain Measurement and Verification Issues, filed January 31, 2019.

Demand Response (DR) Programs

Background and Status

Demand Response refers to the reduction or increase of electricity usage during some time periods (or shifting of usage to another time period), in response to a price signal, financial incentive, environmental condition or a reliability signal. DR programs save ratepayers money by reducing the need to build power plants or avoiding the use of older, less efficient plants that would otherwise be necessary to meet peak demand or avoid curtailment of renewables during times of excess production.
Many DR resources are now bid into CAISO energy markets, enabling them to compete against generation bids and to be dispatched when and wherever needed by the CAISO. By competing against generation resources in these markets, DR resources can make wholesale markets more cost competitive. Future DR programs will be designed to help integrate increasing amounts of renewable power onto the grid by shifting electric loads to periods of high renewable generation.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

Overall, DR budgets have remained relatively flat because IOU portfolio budgets were frozen at 2017 levels.[75] In December 2017, the CPUC approved a 5-year budget for 2018-2022 of $1.16 billion for utility-operated DR programs[76] that will provide approximately 1,600 MWs of DR capacity by 2022.[77] The costs of the programs will be recovered from ratepayers through retail electricity rates but were found to be cost-effective for PG&E and SCE. SDG&E's DR portfolio was found to be cost-ineffective. The Commission authorized SDG&E's DR programs because cost-effective measures made by SDG&E in past years had not fully gone into effect. The CPUC imposed certain conditions on SDG&E going forward, including reducing its portfolio costs by 10% and requiring SDG&E to show continued cost-effective improvements on a quarterly basis. To the extent that DR programs are cost-effective, ratepayers benefit because alternative methods of serving their electricity needs are more expensive.

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75 D.16-09-056.

76 DR was bifurcated into Supply-Side and Load-Modifying DR programs in 2014 in D.14-03-026.

77 D.17-12-003. Note that the 1,600 MWs includes IOU supply side DR programs and certain IOU load modifying programs like the Optional Binding Mandatory Curtailment program. It does not include MWs for time-differentiated pricing programs, which are approved in utility General Rate Cases, or Demand Response Auction Mechanism (DRAM), for which budgets were approved in D.17-10-017.

In 2018, the IOUs began operating from the budget approved in 2017.[78] Implementation of the DR disadvantaged communities' pilots is expected in the second quarter of 2019. The annual budgets in DR Programs,[79] Pilots and Technology,[80] and Support for DR[81] are shown in the tables below.

PG&E Budget 2018-2022 ($ Millions)[82]					
	2018	**2019**	**2020**	**2021**	**2022**
DR Programs	$ 42.87	$ 42.87	$ 42.87	$ 42.87	$ 42.87
Pilots and Technology	$ 10.50	$ 10.95	$ 11.12	$ 8.52	$ 8.67
Support for DR	$ 15.59	$ 13.84	$ 12.98	$ 13.25	$ 13.53
Annual Total	$ 68.96	$ 67.65	$ 66.97	$ 64.63	$ 65.07

Table 8: PG&E Demand Response Portfolio Budget, 2018-22

SCE Budget 2018-2022 ($ Millions)[83]					
	2018	**2019**	**2020**	**2021**	**2022**
DR Programs	$ 145.90	$ 134.51	$ 126.62	$ 119.20	$ 112.54
Pilots and Technology	$ 15.99	$ 11.26	$ 11.12	$ 11.13	$ 11.19
Support for DR	$ 9.29	$ 14.33	$ 8.77	$ 10.19	$ 8.99
Annual Total	$ 171.17	$ 160.10	$ 146.52	$ 140.53	$ 132.71

Table 9: SCE Demand Response Portfolio Budget, 2018-22

78 D.17-12-003 as corrected in D.18-03-041.

79 DR Programs include Category 1: Supply Side Programs, and Category 2: Load Modifying Programs.

80 Pilots and Technology includes Category 3: Demand Response Auction Mechanism (DRAM) and Direct Participation Electric Rule 24/32, Category 4: Emerging and Enabling Technology programs, and Category 5: Pilots.

81 Support for DR includes Category 6: Marketing, Education, and Outreach (ME&O), and Category 7: Portfolio Support (includes EM&V, Systems Support, and Notifications).

82 PG&E's budget includes only expenses; no capital costs were requested in their application. *See* PG&E Prepared Testimony in A.17-01-012, p. 6-3.

83 SCE's budget includes capital costs for equipment, IT and other investments needed for particular DR programs. *See* SCE Prepared Testimony, Volume 3, page 35. The 2019 budget includes $2.28 million in capital technology costs. *See* SCE Cost-Effectiveness Workpaper, Portfolio tab, Annual Inputs for Utility Equipment Cost.

SDG&E Portfolio Budget 2018-2022 ($ Millions)[84,85]					
	2018	2019	2020	2021	2022
DR Programs	$ 5.44	$ 5.44	$ 5.44	$ 5.44	$ 5.44
Pilots and Technology	$ 5.62	$ 5.62	$ 5.62	$ 5.62	$ 5.62
Support for DR	$ 4.67	$ 4.67	$ 4.67	$ 4.67	$ 4.67
Annual Total	$15.73	$15.73	$15.73	$15.73	$15.73

Table 10: SDG&E Demand Response Portfolio Budget, 2018-22

Table 11 shows the calculated residential rate and monthly bill impacts for the 2019 demand response budgets.

2019 DR Portfolio Budgets, Rate and Bill Impacts ($ Millions)					
Utility	2019 Total Budget	2019 Total Budget - Capital	2019 Total Budget - Expense	Residential Rate Impact	Residential Monthly Bill Impact
PG&E	$ 67.65	-	$ 67.65	$0.0010	$0.49
SCE	$ 160.10	$2.28	$157.82	$0.0024	$1.32
SDG&E	$15.73	$0.94	$14.79	$0.0010	$0.44

Table 11: DR Portfolio Budgets, Rate and Bill Impacts, 2019

In November 2018, the IOUs completed work on the click-through authentication and authorization process, which allows customers to easily share their energy data with third-party demand response providers.[86] The CPUC approved funding for the click-through in 2016 and 2017 with budgets for California Independent System Operator (CAISO) registrations, click-through implementation and a budget cap for improvements and additional registrations. Funds were spent in 2016-2019, with some expenditures expected in 2019. The approximate annualized budgets are shown in Table 12.

[84] These are the average annualized budgets because the budgets approved in D.17-12-003 and D.18-03-041 were reduced by 10% for administrative expenses. The annualized budget published in the Decisions show the budget prior to this 10% reduction.

[85] SDG&E's budget includes capital related costs including equipment costs, depreciation, return, and taxes. *See* SDG&E Prepared Testimony, Chapter 6, page EMD-6. The 2019 budget includes $0.94 million in capital technology costs. *See* SDG&E Cost-Effectiveness Workpaper, Portfolio tab, Annual Inputs for Utility Equipment Cost.

[86] PG&E, SDG&E and SCE completed their authorization processes in February 2018, March 2018, and April 2018 respectively.

Rule 24/32 and Click-Through Budgets ($ Millions)[87]						
IOU	2016	2017	2018	2019	2019 Residential Rate Impact	2019 Residential Monthly Bill Impact
PG&E	$ 3.57	$ 7.66	$ 7.66	$ 2.5	$0.00004	$0.018
SCE	$ 0.5	$ 2.48	$ 2.47	$ 0.5	$0.00001	$0.004
SDG&E	$ 1.5	$ 4.55	$ 4.55	$ 1.5	$0.00010	$0.045

Table 12: CAISO Registration Rule 24/32 and Click Through Budgets

During 2019, the CPUC will develop an administrative record and possibly issue decisions authorizing the expansion of the click-through authorization process to DER and energy management providers, as well as improvements designed for DR.[88]

Energy Division Demand Response Auction Mechanism (DRAM) Evaluation Final Report was released on January 4, 2019, covering delivery years 2016 to 2018. The DRAM pilot tested "the feasibility of procuring … Resource Adequacy (RA) with third part[ies] … through an auction mechanism, and the ability of winning bidders to integrate … into the CAISO market."[89] The DRAM budget was low in 2016, remained flat in 2017 and 2018, and increased in 2019 because a second auction was authorized for delivery year 2019, as shown in Table 13.

DRAM Budgets ($ Millions)[90]							
IOU	2016 DRAM I	2017 DRAM II	2018 DRAM IIIA	2019 DRAM IIIB	2019 DRAM IV	2019 Residential Rate Impact	2019 Residential Monthly Bill Impact
SCE	$ 4.0	$ 6.0	$ 6.0	$ 6.0	$ 6.0	$ 0.0002	$ 0.10
PG&E	$ 4.0	$ 6.0	$ 6.0	$ 6.0	$ 6.0	$ 0.0002	$ 0.09
SDG&E	$ 1.0	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 0.0002	$ 0.09
Total	$ 9.0	$ 13.5	$ 13.5	$ 13.5	$ 13.5		

Table 13: IOU Demand Response Auction Mechanism Budgets, 2016-2019

87 These budgets were authorized in D.16-06-008, D.17-06-005, and Resolution E-4868.
88 Applications 18-11-015, 016, and 017 were filed on November 26, 2018.
89 D.14-12-024 Settlement, p. 24.
90 Adapted from Energy Division Public Report Presentation on DRAM at the January 16, 2019 workshop, available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442460871 (accessed April 5, 2019).

The report found that the pilot results were mixed and recommended a 5-6 year continuation of the DRAM solicitation conditioned on certain critical improvements. By mid-2019, a CPUC decision is expected on whether the DRAM should continue, the design of the auction mechanism, and the IOU budget, if it continues.

The Load Shift Working Group Final Report was released the first quarter of 2019.[91] The report presented six different proposals for new bi-directional DR resources that increase electricity consumption to mitigate renewable over-generation.[92] The proposals are will be considered in a future rulemaking.[93] The proposals will have budget implications, but the CPUC has not yet determined when this rulemaking will be initiated.

Finally, during 2019, first-time implementation of CPUC's prohibited resource policy will progress and the CPUC will develop a record for the verification of its prohibited resources policy via meters and logger devices.[94] Meters and logger devices would have cost implications, but the CPUC has not yet made a determination.

Longer-Term Trends (May 2020 and Beyond)

The CPUC expects many of the activities currently in place to continue in the long term. As shown above, the IOU portfolio has been approved for 2018-2022. If the CPUC decides to continue the DRAM, the program may continue long-term with continuous improvements and evaluation. Now that the Load Shift Working report has been released, the CPUC expects to address new models of DR in a rulemaking, with cost implications if pilots are adopted. As discussed above, improvements to the click-through authorization process and meter and logger requirements could have cost implications as well.

DR proceedings have often taken a cautious approach towards spending ratepayer funds. For example, Rule 24/32 funding was approved in phases. The CPUC will likely continue this cautious approach to DR funding. Further, the new rulemaking may consider additional ways to reduce IOU budgets.

Residential Default Time-of-Use (TOU) Rates

While not a demand-side program, residential default time-of-use (TOU) rate structure, as part of a larger legislative mandate to reform residential rates, is included here. Offering time-based rates

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[91] The report was released January 31, 2019 and is available at: https://gridworks.org/wp-content/uploads/2019/02/LoadShiftWorkingGroup_report.pdf (accessed on April 4, 2019).
[92] D.17-10-017; Calling on customers to consume or take energy is commonly known as "reverse Demand Response."
[93] Load Shift Working Group Final Report, p. 1.
[94] Applications 18-10-008, 009, and 010.

such as TOU pricing is often included as one of the methods of engaging customers in demand response efforts.

Background and Status

In 2013, Assembly Bill (AB) 327 (Perea, 2013) was enacted into law to reform residential rates, giving the Commission authority to direct the IOUs to employ TOU rates starting no earlier than January 1, 2018.[95] The CPUC set a goal of residential default TOU by 2019 and provided direction to the three major electric IOUs regarding specific steps that must be taken to reform residential rate design structure with an envisioned end-state of default TOU rates and an optional two-tier rate structure.[96] Since then, the CPUC has developed methodologies for setting TOU periods, and ordered residential opt-in TOU pilots and residential default TOU pilots in PG&E, SCE, and SDG&E's service territories.

TOU rate structure pricing provides customers a financial incentive to shift demand away from evening peak usage. Under TOU rate plans, electricity costs more in the evening when supply from renewable resources is lower than customer demand, and costs less in other usage periods. The residential opt-in TOU pilots, conducted from June 2016 to December 2017, were designed to produce insight into customers' ability to accept and respond to TOU rates, principally by studying the load and bill impacts of implementing TOU rates. Another important aspect of the pilot design concerned assessment of any potential hardship impacts on certain customers.[97] The final evaluation report on the residential opt-in TOU pilots was issued March 2018 and focused primarily on load impacts from the second summer period in 2017 as well as the persistence of load impacts across the two summers for the subset of customers that were enrolled for the full duration of the pilot.[98]

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

In March 2019, the residential default TOU pilots were completed. The default TOU pilots were designed to fine-tune customer transition to default TOU education and test system operability prior to full rollout of default TOU. While it is important to have all Californians understand the "why" and "how" to shift energy usage behaviors, it is equally important that the customers defaulting to a

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95 Residential rate reform was only one part of AB 327.

96 Decision (D.)15-07-001; Residential default TOU rates implementation was conditioned on meeting the requirements of Public Utilities Code Section 745. The optional two-tiered rate structure also includes High-Usage Charge (HUC) rates.

97 Public Utility Code Section 745 requires that the CPUC ensure that any default TOU rate schedule does not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate regions. In Decision (D.)17-09-036, the CPUC ordered PG&E, SCE, and SDG&E to exclude California Alternate Rates for Energy and Family Electric Rate Assistance eligible customers in the IOUs' previously-defined hot climate zones (and included SCE's climate zone 10) from the default time-of-use pilot and from default time-of-use rates.

98 *See* http://www.cpuc.ca.gov/General.aspx?id=12154 .

TOU rate understand the potential impact, how they can be successful on the new rate, and ultimately that they have rate choices.

As part of evaluating the default TOU pilots, the IOUs have submitted preliminary load impact data for Summer 2018 which indicates that overall peak load reduction under the default TOU pilots is less than under the opt-in TOU pilots. This is to be expected, however, as opt-in TOU pilot participants received a financial incentive to participate in the opt-in TOU pilots, and self-selection bias could skew load reduction response numbers higher in the opt-in TOU pilots than in the default TOU pilots. Final load impact data for the default TOU pilots is expected later in 2019. Rate and bill impacts corresponding to the estimated remaining spend for the default TOU pilots are shown in Table 14.[99]

Default Pilots	2017-2019 Budgets	Spending in 2017-2018	Remainder as of Q1 2019	2019 Residential Rate Impact	2019 Residential Monthly Bill Impact
PG&E	$ 14,700,000	$ 12,500,000	$ 2,200,000	$0.00003	$0.016
SCE	$ 21,100,000	$ 8,400,000	$ 12,700,000	$0.00020	$0.110
SDG&E	$ 11,900,000	$ 8,700,000	$ 3,200,000	$0.00022	$0.095

Table 14: Default TOU Pilot Budgets and Estimated Remaining Spend for 2019

In 2018, Marketing, Education & Outreach plans and budgets were finalized for each of the IOUs as shown in Table 15, with different levels of spending authorized for each IOU based on need and a reasonableness review of activities, and in accordance with TOU implementation timelines.

IOU ME&O Plan Budgets (Includes Rate Reform, Default TOU and Market Research Spend)					
IOU	2017-2022 Budget (PG&E/SCE)	2017-2020 Budget (SDG&E)	2019 Levelized Spend	2019 Residential Rate Impact	2019 Residential Monthly Bill Impact
PG&E	$ 46,700,000		$ 7,783,333	$ 0.0001	$ 0.06
SCE	$ 39,400,000		$ 6,566,667	$ 0.0001	$ 0.05
SDG&E		$ 19,400,000	$ 4,850,000	$ 0.0003	$ 0.14

Table 15: IOU Marketing, Education & Outreach Plan Budgets

In December 2018, the CPUC authorized SDG&E to begin transitioning eligible residential customers to default TOU rates in March 2019,[100] and PG&E and SCE were authorized by the CPUC to begin transitioning eligible residential customers to TOU rates beginning October 2020.[101]

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[99] Assumes the remaining budget will be spent in 2019.

[100] Decision (D.)18-12-004, "Phase IIA Decision Addressing Residential Default Time-of-Use Rate Design Proposals and Transition Implementation."

[101] Decision (D.)18-05-011. PG&E and SCE start dates are subject to approval of the utilities' specific rate design proposals and implementation details for the transitions, which are presently being considered in Phase IIB of consolidated Application (A.)17-12-11 et al.

A decision in Phase IIB of the consolidated Rate Design Window (RDW) applications A.17-12-11 et al with respect to residential default TOU rate design proposals and transition implementation is expected later in 2019.

Longer-Term Trends (May 2020 and Beyond)

California's statewide transition to residential default TOU for customers of the major electric IOUs is of a magnitude that has not been undertaken anywhere else in the United States. The most-recently available data for residential customers enrolled on TOU rates in the United Sates shows 2.6 million customers as of 2017.[102] SDG&E plans to transition approximately 750,000 eligible residential customers to TOU pricing over a ten-month period beginning March 2019 through December 2019. PG&E and SCE plan to transition approximately 2.7 million and 3.3 million eligible customers, respectively, beginning October 2020 and ending December 2021.

The expectation with California's major electric IOUs' transition of eligible customers to residential default TOU is that large-scale changes in individually-aggregated customer usage behavior will contribute to GHG emission reduction goals. Independently of GHG emission reductions achieved under residential default TOU, economic benefits of customers shifting load away from high-demand periods may be realized. These economic benefits consist of the IOUs delaying or avoiding costs associated with infrastructure additions or upgrades as the mismatch gap narrows between customer demand and electricity supply.

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102 U.S. EIA, 2017, Dynamic Pricing, Residential Customers enrolled in Time-of-Use pricing. EIA publishes data from utilities that offer time-based rate programs, such as time-of-use rates, on the number of utility customers that are enrolled in these programs. EIA data is not further broken down by whether customers are enrolled in opt-in TOU rates or default TOU rates.

Income Qualified Assistance Programs

Background and Status

California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA)

The California Alternate Rates for Energy (CARE) program, is a low-income energy rate assistance program that provides a discount on energy rates to qualifying low-income households with incomes at or below 200% of the Federal Poverty Guideline. The CARE program currently provides a rate discount ranging from approximately 30%-35% on electric bills and 20% on natural gas bills.

The Family Electric Rate Assistance (FERA) program, provides families of three or more, whose household income slightly exceeds the CARE allowances, with a 18% discount on their electricity bill.[103] The income limits of the FERA program range from 200% to 250% of the Federal Poverty Guidelines. Public Utilities Code Section 739.1 (f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based upon their level of income and economic need.

Energy Savings Assistance Program (ESA)

The Energy Savings Assistance (ESA) program provides no-cost home weatherization services, energy efficiency measures, and energy education to help eligible low-income households conserve energy, reduce energy costs and improve health, comfort and safety. Households with total annual incomes at or below 200% of federal poverty guidelines qualify for the ESA program.

The Energy Savings Assistance Common Area Measures Program (ESA CAM) launched in late 2018 and provides no-cost energy efficiency measures to the common areas or shared energy systems within a building or property of deed-restricted multifamily buildings with a majority of eligible low-income tenant households. At least 65% of tenant households must have total annual incomes at or below 200% of the federal poverty guidelines to qualify for the ESA CAM program. ESA CAM is not a part of the investor-owned utilities' total revenue requirement; the funding comes from previously unspent ESA funds allocated by Decision 16-11-022, as modified by Decision 17-12-009.

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[103] In 2018, SB 1135 required the commission to continue the FERA program for the state's three largest electrical corporations, and that effective January 1, 2019 the program discount be an 18% line-item discount applied to an eligible customer's bill calculated at the applicable rate for a monthly or other billing period.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

California Alternative Rates for Energy (CARE) and Family Electric Rate Assistance (FERA)

For the 2018 program year, the average annual budget for the CARE program was $1.3 billion and the average annual expenditures for the FERA program was $12.2 million. As of December 2018, approximately 4.5 million households were enrolled in CARE and approximately 51,000 household were enrolled in FERA. Table 16 shows the 2018 spending for CARE and FERA programs.

	2018 FERA[104]	2018 CARE[105]		
	Expenditures	Administrative Expense	Rate Discounts	Total CARE
PG&E	$ 5,262,751	$11,865,518	$610,623,696	**$ 622,489,214**
SCE	$ 5,383,526	$7,337,847	$376,226,811	**$ 383,564,658**
SDG&E	$ 1,522,331	$5,927,954	$126,165,599	**$ 132,093,553**
SoCalGas	N/A	$7,910,991	$111,634,300	**$ 119,545,291**
Total	**$12,168,608**	**$33,042,310**	**$1,224,650,406**	**$1,257,692,716**

Table 16: 2018 CARE and FERA Expenditures

Examination of the population eligible but not enrolled in CARE has been scoped into the next Low Income Needs Assessment Study (LINA) which is due December 31, 2019. No additional cost/budget implications are anticipated because of the study through 2020, which marks the end of the current program cycle.

Energy Savings Assistance Program (ESA)

For program years 2018-2020 the average annual authorized budget for the ESA program is $547million and average household treatment goals are approximately 401,500 homes per year.[106] ESA budgets have increased significantly over the years, as new measures are offered, and it is increasingly difficult and expensive to enlist hard-to-reach households, thus resulting in potential

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[104] The FERA Program does not have a separate, authorized budget. The program is administered incrementally within the CARE Program Administrative budget.

[105] The CARE budget was authorized in D.16.11-022 as modified by D.17-12-009. Expenditures shown are from the IOUs' December 2018 Monthly CARE and ESA Program Report, *see* A.14-11-007 docket.

[106] The IOUs filed mid-cycle advice letters with updated ESA program budgets and household treatment goals: AL 3990-G/5329-E (PG&E), 3824-E (SCE), 5325-G (SCG), and 3250-E/2688-G (SDG&E).

cost and rate impacts. The IOUs are on track to achieve the statute goal to treat all willing and eligible low-income households by 2020 through ESA (Public Utilities Code 382(e)).

In the current program cycle, each month the IOUs provide a report with updates on ESA expenditures and households treated. Per the IOUs' 2018 Investor-Owned Utility ESA-CARE Monthly Reports,[107] 2018 spending is as shown in Table 17.

Utility	ESA Expenses 2018
Pacific Gas and Electric	$124,890,181
Southern California Edison	$63,476,452
Southern California Gas	$91,934,323
San Diego Gas & Electric	$22,912,292
TOTAL	$303,213,248

Table 17: 2018 ESA Expenditures

In the first part of 2019, the Commission will provide guidance for the next low-income programs. The investor-owned utilities will submit applications to the Commission for the program years of 2021 to 2026. There will be an open proceeding to consider the applications.

[107] *See* A.14-11-007 docket. The IOUs will submit their annual reports on 2018 activity, including ESA CAM, on May 1, 2019.

4. Wildfire Mitigation Plans

California's wildfire risk has increased in recent years due to climate change, drought, and other factors. Indeed, the safety of California communities requires additional measures designed to address the higher level of catastrophic wildfire risk posed by electrical lines and equipment. To this end, California Senate Bill 901 (SB 901), enacted in 2018, adopted new provisions of Public Utilities Code (PUC) Section 8386, requiring electric utilities to prepare and submit wildfire mitigation plans that describe the utilities' plans to prevent, combat, and respond to wildfires affecting their service territories. The commission opened a rulemaking[108] on October 25, 2018 to review initial utility Wildfire Mitigation Plans (WMP) and refine the process for the review and implementation of wildfire mitigation plans to be filed in future years.[109]

Proposed costs in the WMPs are each IOU's initial cost estimates.[110] Actual costs may vary substantially depending on actual conditions and requirements including, but not limited to: skilled labor resource constraints, costs of labor, supply chain disruptions, permit acquisitions, weather or other environmental or climatological factors, challenges regarding access rights to perform the work, as well as other execution risks. In addition, while the costs presented in this section are 2019 estimates, costs in several of the categories are of an ongoing or protracted nature and are projected to continue beyond 2019.

The IOUs' updated mitigation plan filings are anticipated for February 2020. The updated mitigation plan filings may have revised cost estimates, including the amount and type of work that needs to be done, updated unit costs, and additional information regarding the volume of resources necessary to carry out these programs based on recent, actual experience. These WMPs have not been approved by the Commission, and costs that are not yet reflected in the IOUs' revenue requirements are subject to review during a cost recovery proceeding.

[108] R.18-10-007.

[109] PG&E Wildfire Mitigation Plan:
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M263/K673/263673423.PDF ;
SCE Wildfire Mitigation Plan: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=263645320 ;
SDG&E Wildfire Mitigation Plan: http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=263673421 .

[110] ALJ Thomas' Ruling in R.18-10-007 dated January 17, 2019 ordered the IOUs to include cost estimates for each activity in Chapter 4 of each IOU's WMP. Costs in this report correspond only to WMP Chapter 4 costs.

To address wildfire risks, PG&E is proposing in its WMP the following activities:

Operational Practices: PG&E has developed a number of enhanced operational practices that are designed to further reduce the risk of wildfires during elevated fire danger conditions. These enhancements include enhanced controls with respect to recloser operations and other measures to prevent potential ignitions, including strengthened personnel work procedures, deploying Safety and Infrastructure Protection Teams (SIPT) with fire- fighting capabilities, and operating heavy-lift helicopters for enhanced fire suppression and restoration efforts, available at CAL FIRE's discretion. These measures will be in place by June 1, 2019.

Wildfire Safety Inspection Programs: PG&E will perform inspection of its electrical assets in High Fire-Threat District (HFTD) areas, including approximately 685,000 distribution poles, 50,000 transmission structures, and 200 substations by June 2019. These inspections include ground inspections, drone and helicopter inspections where needed, and climbing inspections of every transmission tower. Corrective actions will be taken to address any issues identified as risks as a result of the inspections.

System Hardening Programs: System hardening reduces potential fire risk associated with the overhead distribution system and includes replacing bare overhead conductor with covered conductor, select undergrounding where appropriate, replacing equipment with equipment identified by the California Department of Forestry and Fire Protection (CAL FIRE) as low fire risk, upgrading or replacing transformers to operate with more fire-resistant fluids, and installing more resilient poles to increase pole strength and fire resistance. PG&E plans to reconductor 150 circuit miles of the highest risk circuits in HFTD areas in 2019 as well as harden an additional 7,100 circuit miles in HFTD areas that it has identified through ignition modeling and field analysis as the highest risk beyond the year 2019.

Enhanced Vegetation Management: PG&E will perform vegetation management on approximately 2,450 circuit miles in HFTD areas by the end of 2019, including targeted removal of vegetation fuels close to power lines. The scale, scope and complexity of this work necessitate that, to address the approximately 25,200 distribution circuit miles in HFTD areas, this program is established as a multi-year effort. In addition, PG&E forecasts removing approximately 375,000 trees in 2019 that have a higher potential to fail including at-risk species in addition to dead, dying or other hazard trees.

Enhanced Situational Awareness: PG&E is increasing its situational awareness—its knowledge of local weather and environmental conditions—to obtain real time knowledge of localized conditions that affect wildfire risk on a more granular level. This type of information is critical for both wildfire prevention and Public Safety Power Shut-Off (PSPS) events and is accessible to respective fire response agencies.

Public Safety Power Shutoff (PSPS): PG&E implemented its PSPS program to proactively de-energize lines that traverse Tier 3 HFTD areas under extreme fire risk conditions in 2018. PG&E is significantly expanding its PSPS program scope to include high voltage transmission lines and the highest fire risk areas. In addition, PG&E will be working with customers to provide them with information regarding PSPS events generally, and to provide the most up to date information before and during PSPS events. This includes alerting 5.4 million PG&E electric customer premises of the potential for PSPS events. Extensive customer outreach will begin in the first quarter of 2019 and will continue throughout the year. To the extent possible, PG&E will alert customers that a PSPS event could occur within 48 hours. PG&E is actively exploring and developing additional services and programs to support customers during PSPS events with a focus in the short term on customers who require a continuous electric supply for life support, as well as critical services (i.e., first responders, hospitals, telecom, and water agencies).

Alternative Technologies: PG&E is implementing pilot programs to evaluate alternative technologies that
may harden and modernize the electrical system and improve operational capabilities. PG&E has a demonstration project planned in 2019 to test the capabilities of technology to directly reduce the risk of wildfires for single line to ground faults and an enhanced situational awareness project that can help detect and locate downed distribution lines more quickly to enable faster response.

PG&E Wildfire Mitigation Plan 2019 Cost Estimates

Table 18 summarizes the cost estimates filed February 6, 2019 in PG&E's WMP for proposed 2019 activities, and conversion of the estimates to revenue requirement.[111] These cost estimates are not reflected in their entirety in 2019 rates,[112] however, for illustrative purposes, the rate and bill impacts reflect these cost estimates as if cost recovery were to take place in 2019. Actual cost recovery will occur in 2020 and later. Bill impact estimates as a result of this 2019 cost recovery illustrative presentation are based on proposed cost estimates that have not been approved by the CPUC.

[111] O&M expenses directly translate to revenue requirement, however, capital costs reflect capital spend and must be converted to the corresponding revenue requirement. Capital is converted to revenue requirement by applying authorized return on rate base and a factor to adjust the return on rate base to a gross revenue requirement. 2019 is considered the first year for purposes of converting capital spend to revenue requirement.

[112] 2019 rates may reflect certain costs approved as part of PG&E's 2017 GRC proceeding.

Category	2019 Plan Cost ($000)		Conversion to Revenue Requirement ($000)	
	Capital	**O&M Expense**	**Capital**	**O&M Expense**
Wildfire Safety Strategy and Programs	500	8,000	55	8,000
Operational Practices	8,300	14,700	917	14,700
Wildfire Safety Inspection Programs*	764,500	332,500	84,440	332,500
System Hardening Programs	798,400	300	88,184	300
Enhanced Vegetation Management*	-	431,700	-	431,700
Enhanced Situational Awareness	8,900	23,000	983	23,000
Public Safety Power Shutoff	15,800	16,500	1,745	16,500
Alternative Technologies	2,100	7,200	232	7,200
Support*	24,500	15,500	2,706	15,500
Sub-Total	**1,623,000**	**849,400**	**179,262**	**849,400**
Total	**2,472,400**		**1,028,662**	
Residential Rate Impact ($/kWh)			**$0.0146**	
Monthly Residential Bill Impact			**$7.43**	

***Plan categories with cost ranges. The mid-point of the range is presented.**

Table 18: PG&E Proposed 2019 WMP Cost Estimates

PG&E's 2019 WMP cost of $2.472 billion is estimated to have a potential cost impact to the residential class of an incremental rate of $0.0146/kWh and an incremental monthly bill of $7.43.[113]

All costs associated with PG&E's 2019 WMP are considered incremental for purposes of evaluating the potential cost implications of measures proposed in the plan; however, approximately $48.7 million in costs were included in the 2017 GRC and are already reflected in the revenue requirement, and $7.0 million in costs are recovered through the Electric Program Investment Charge, for a total of $55.7 million. Removal of $55.7 million that is already in the revenue requirement from the total plan costs results in an adjusted total cost of $2.417 billion not yet in the revenue requirement. Table 19 summarizes the 2019 cost estimates adjusted downward to present only costs not yet in the revenue requirement, conversion of these estimates to revenue requirement, and the resulting residential rate and monthly bill impacts for the 2019 WMP proposed by PG&E.

[113] For basic assumptions of the calculated impacts, see SB 695 Report section, "Incremental Revenue Requirement Customer Rate and Bill Impacts." Rate and bill impact figures presented here do not take into account how the revenue requirement will be recovered (e.g. through the distribution rate component for all customers, or some other recovery mechanism).

Category	2019 Plan Cost Not Yet in Revenue Requirement ($000)		Conversion to Revenue Requirement ($000)	
	Capital	**O&M Expense**	**Capital**	**O&M Expense**
Wildfire Safety Strategy and Programs	500	8,000	55	8,000
Operational Practices	8,300	14,700	917	14,700
Wildfire Safety Inspection Programs*	750,500	326,000	82,894	326,000
System Hardening Programs	776,400	-5,700	85,755	-5,700
Enhanced Vegetation Management*	-	431,500	-	431,500
Enhanced Situational Awareness	8,900	23,000	983	23,000
Public Safety Power Shutoff	15,800	16,500	1,745	16,500
Alternative Technologies	2,100	200	232	200
Support*	24,500	15,500	2,706	15,500
Sub-Total	**1,587,000**	**829,700**	**175,287**	**829,700**
Total	**2,416,700**		**1,004,987**	
Residential Rate Impact ($/kWh)			**$0.0142**	
Monthly Residential Bill Impact			**$7.26**	

***Plan categories with cost ranges. The mid-point of the range is presented.**

Table 19: PG&E Proposed 2019 WMP Cost Estimates (Not Yet in Revenue Requirement)

The costs in PG&E's WMP generally align with those forecasted for 2019 in PG&E's 2020 GRC Phase I filing,[114] with some exceptions. Cost forecasts that deviate from those filed in PG&E's 2020 GRC, or with respect to other previously filed documents such as the CEMA by approximately 15 percent or more have been updated with PG&E's latest forecasted costs.[115] PG&E's 2019 WMP costs will generally be reviewed for reasonableness and authorized for recovery during its 2020 GRC.

Southern California Edison Company's Wildfire Mitigation Plan

To address wildfire risks, SCE is proposing in its WMP the following strategies and programs, including both existing and new work activities.

Operational Practices: SCE has assigned responsibility for monitoring and operating its electric system to Grid Operations. SCE restricts certain operations and switching procedures in High Fire Risk Areas (HFRA) during Red Flag Warnings (RFW) and elevated fire weather threats. These operating restrictions are defined in SCE's System Operating Bulletin (SOB) 322 that outlines the operational protocols for overhead distribution and sub-transmission equipment within HFRA.

[114] A.18-12-009.

[115] Total plan costs include approximately $6.2 million CEMA capital costs and $100.6 million CEMA expense. PG&E proposes to recover the authorized CEMA capital costs and expense that have already been incurred over a 2-year period beginning on January 1, 2019, or as soon as possible thereafter, as part of its Annual Electric True-Up (AET) advice filings.

These guidelines include RFW restrictions, switching protocols, enabling of protective devise, and patrolling requirements. In 2019, SCE will review and update SOB 322 to reflect lessons learned from past elevated fire weather threats and integrate, where applicable, new and improved data from its situational awareness resources. In addition, SCE plans to hire an additional meteorologist as part of its wildfire infrastructure protection team.

Wildfire Safety Inspection Programs: SCE continues to review and assess its inspection and maintenance programs to keep pace with wildfire threats. To address evolving wildfire risk beyond existing programs, SCE commenced its Enhanced Overhead Inspections (EOI) initiative. SCE's goal is to conduct inspections of all overhead transmission structures (about 50,000 structures) and distribution structures (about 380,000 structures), and equipment in HRFA with a focus on potential ignition risk conditions. These inspections started in late 2018 and SCE is attempting to complete them before the start of the height of the 2019 wildfire season. In addition, SCE's Quality Oversight / Quality Control group will perform independent quality control inspections on approximately 7,500 transmission and distribution structures in HRFA based on EOI in 2019. Infrared inspection cycles of facilities and equipment also started in 2019.[116]

System Hardening Programs: SCE's system hardening effort is largely an ongoing, multi-year program focused on wildfire prevention (i.e., reducing ignitions) and enhancing system resiliency (i.e., reducing damage to electrical infrastructure from fires). For 2019, SCE is planning to install at least 96 circuit miles of covered conductor in HRFA and is targeting the proactive replacement of approximately 5,500 circuit miles of bare distribution primary overhead conductor in HRFA by 2025. In addition, in 2019 SCE plans to install in HRFA at least 1,100 composite poles, 7,500 current-limiting fuses (CLF), and 50 new remote-controlled automatic reclosers (RAR). Other 2019 activities include updating at least 150 existing RAR settings, developing a circuit breaker (CB) update plan, and conducting an evaluation of undergrounding in HRFA.[117]

Vegetation Management Programs: SCE's vegetation management program involves ongoing activities related to tree inspection, pruning, and removal, and weed abatement in proximity to SCE's distribution and transmission lines. SCE proposes to expand its vegetation management activities to begin assessing the structural condition of tress in HRFA that are not dead or dying but could nevertheless fall into or otherwise impact electrical facilities. Under this program, SCE anticipates it will perform at least 125,000 tree-specific threat assessments and mitigate, through removal or trimming, at least 7,500 trees in 2019. SCE will also continue to conduct Drought Relief Initiative (DRI) activities within HRFA to identify and remove dead, dying, or diseased trees affected by drought conditions, and will do Light Detection and Ranging (LiDAR) inspections on select

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[116] Intrusive pole inspections to identify rot and decay and pole loading assessments are part of existing inspection programs.

[117] RAR replacement, capacitor bank replacement, deteriorated pole replacement, PCB transformer replacement, transmission line rating remediation, insulator washing, and overhead reconductoring and branch line fuse installation are part of existing system hardening programs.

transmission lines to identify potential subject trees assessed under the Hazard Tree Mitigation program. In addition, SCE plans to inspect and clear brush to 10 feet radial clearance at the base of a pole for at least 25,000 poles and expand tree-to-line clearance distances to 12 feet for certain line voltages at time of maintenance. To verify compliant contractor work, SCE's goal is to inspect vegetation adjacent to approximately 400 transmission circuit miles and approximately 450 distribution circuit miles.[118]

Situational Awareness Programs: SCE is enhancing its situational awareness capabilities by leveraging more detailed circuit level information to better understand how weather conditions might impact public safety and utility infrastructure in HFRA. This includes creation of a high-resolution weather model specific to SCE's service territory and strategically installing weather stations to enhance the high-resolution weather model and provide real time data near circuits in HFRA. SCE is planning to install in HRFA at least 315 weather station units and install at least 62 additional HD cameras on 31 towers. Other activities planned for 2019 include enhancing or procuring additional weather data modeling and monitoring tools, as well as implementation of Asset Reliability and Risk Analytics tools.

Public Safety Power Shutoff (PSPS): Execution of pre-emptively shutting off power, or proactively de-energizing circuits within HFRA if data sources indicate an imminent and significant wildfire risk, is ultimately based on the judgment of the Incident Management Team (IMT). SCE utilizes its Energy Outage Notification System (EONS) to create and deliver customized outage communications in the customers' preferred digital channel(s) regarding de-energizing events. General outreach to customers who are in HRFA regarding PSPS de-energizing events will occur through an annual letter. Additional engagement with critical care customers and essential services providers is also outlined.

Alternative Technologies: SCE continues to explore technologies that will reduce the probability of an ignition event and/or reduce public exposure to a hazardous condition during periods of high fire risk. In 2019, in addition to wildfire mitigation program studies proposed in its Grid Safety and Resiliency Program (GSRP) application,[119] SCE will do two alternative technology pilot programs, several alternative technology evaluations, and develop standard installation practices for several alternative technology implementations.

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[118] Road and right-of-way maintenance are part of existing vegetation management programs.

[119] A.18-09-002.

SCE Wildfire Mitigation Plan 2019 Cost Estimates

Table 20 summarizes the cost estimates filed February 6, 2019 in SCE's WMP for proposed 2019 activities, and conversion of the estimates to revenue requirement.[120,121] These costs are not reflected in their entirety in 2019 rates,[122] however, for illustrative purposes, the rate and bill impacts reflect these cost estimates as if recovery were to take place in 2019. Actual cost recovery will occur in 2020 and later. Bill impact estimates as a result of this 2019 cost recovery illustrative presentation are based on proposed cost estimates that have not been approved by the CPUC.

Category	2019 Plan Cost ($000)[123]		Conversion to Revenue Requirement ($000)	
	Capital	O&M Expense	Capital	O&M Expense
Operational Practices	-	500	-	500
Wildfire Safety Inspection Programs	112,700	310,600	12,367	309,400
System Hardening Programs	892,300	15,000	97,918	16,200
Vegetation Management Programs	-	166,100	-	166,100
Situational Awareness Programs	20,800	8,800	2,283	8,800
Public Safety Power Shutoff	-	5,600	-	5,600
Alternative Technologies	1,600	600	176	600
Sub-Total	**1,027,400**	**507,200**	**112,744**	**507,200**
Total	**1,534,600**		**619,944**	
Residential Rate Impact ($/kWh)			**$0.0093**	
Monthly Residential Bill Impact			**$5.17**	

Table 20: SCE Proposed 2019 WMP Cost Estimates

SCE's 2019 WMP cost of $1.535 billion is estimated to have a potential cost impact to the residential class of an incremental rate of $0.0093/kWh and an incremental monthly bill of $5.17.[124]

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120 O&M expenses directly translate to revenue requirement, however, capital costs reflect capital spend and must be converted to the corresponding revenue requirement. Capital is converted to revenue requirement by applying authorized return on rate base and a factor to adjust the return on rate base to a gross revenue requirement. 2019 is considered the first year for the purposes of converting capital spend to revenue requirement.

121 SCE presents costs for "2019 Goal" and "2019 Expansion / Acceleration" with discrete values (i.e. no cost ranges). The sum of these costs is presented here.

122 2019 rates reflect certain costs that may be approved as part of SCE's 2018 GRC proceeding, Application (A.)16-09-001. A Preliminary Decision in A.16-09-001 was issued April 12, 2019.

123 Certain Table 21 line item plan costs differ from those presented in the WMP due to reclassification into cost categories of $575 million in capital costs and $147 million in O&M expense with SB 901 Activity Identifier "N/A."

124 For basic assumptions of the calculated impacts, see SB 695 Report section, "Incremental Revenue Requirement Customer Rate and Bill Impacts." Rate and bill impact figures presented here do not take into account how the revenue requirement will be recovered (e.g. through the distribution rate component for all customers, or some other recovery mechanism).

All costs associated with SCE's 2019 WMP are considered incremental for purposes of evaluating the potential cost implications of measures proposed in the plan; however, approximately $717.9 million in costs were included in the 2018 GRC and are already reflected in the revenue requirement.[125] Removal of $717.9 million that is already in the revenue requirement from the total plan costs results in an adjusted total of $816.7 million not yet in the revenue requirement. Table 21 summarizes the 2019 cost estimates adjusted downward to present only costs not yet in the revenue requirement, conversion of these estimates to revenue requirement, and the resulting residential rate and monthly bill impacts for the 2019 WMP proposed by SCE.[126]

Category	2019 Plan Cost Not Yet in Revenue Requirement ($000)		Conversion to Revenue Requirement ($000)	
	Capital	**O&M Expense**	**Capital**	**O&M Expense**
Operational Practices	-	500	-	500
Wildfire Safety Inspection Programs	112,700	176,100	12,367	176,100
System Hardening Programs	317,300	6,800	34,819	6,800
Vegetation Management Programs	-	166,100	-	166,100
Situational Awareness Programs	20,800	8,800	2,283	8,800
Public Safety Power Shutoff	-	5,600	-	5,600
Alternative Technologies	1,400	600	154	600
Sub-Total	**452,200**	**364,500**	**49,623**	**364,500**
Total	**816,700**		**414,123**	
Residential Rate Impact			**$0.0062**	
Monthly Residential Bill Impact			**$3.45**	

Table 21: SCE Proposed 2019 WMP Cost Estimates (Not Yet in Revenue Requirement)

The costs in SCE's WMP reflect forecasted costs in SCE's pending 2018 GRC Phase I filing,[127] pending GSRP filing, and costs included in SCE's CEMA account.[128] SCE's new mitigating

125 SCE's 2018 GRC is pending. A Preliminary Decision in A.16-09-001 was issued April 12, 2019. Some 2018 GRC WMP costs may have "secondary wildfire risk mitigation benefits," defined as "not primarily designed in the first place to reduce wildfire risk, but nonetheless have wildfire risk mitigation benefits," *see* WMP, p. 48.

126 Table 7-1 in SCE's WMP does not clearly indicate that "2019 Expansion / Acceleration" costs include "2019 Goal" costs, and "2019 Goal" costs should be netted from "2019 Expansion / Acceleration" costs to present these additional costs. Per Energy Division staff data request with SCE, SCE indicated that approximately $137 million should be netted from 2019 Plan Cost Not Yet in the Revenue Requirement to reflect SCE's methodology for presenting the total incremental costs in Table 7-1. Removal of $106.2 million from capital costs and $30.5 million from O&M expense results in an approximate total cost of $680 million which equates to about $372.0 million not yet in the revenue requirement, and an incremental residential rate impact of $0.0056 and incremental residential monthly bill impact of $3.10. SCE classifies the approximate total cost of $680 million as 2019 "High" case.

127 A.16-09-001.

128 New mitigating strategies / program costs are approximately $436.5 million to be recorded in the GSRP MA, and $338.7 million to be recorded in SB 901 MA and the FHPMA. In addition, $41.5 million will be recorded as CEMA expenses.

strategies and program costs will be tracked in three memorandum accounts (MA): the GSRP MA; the Senate Bill (SB) 901 MA; and the Fire Hazard Prevention MA (FHPMA). SCE will seek cost recovery of SB 901 MA and the FHPMA WMP incremental costs in its 2021 GRC.

San Diego Gas and Electric Company's Wildfire Mitigation Plan

To address wildfire risks, SDGE is proposing in its WMP the following activities:

Operational Practices: During 2019, SDG&E will use variety of situational awareness inputs to determine the appropriate operating environment given current and expected wildfire conditions. Among these inputs are Fire Potential Index (FPI), Santa Ana Wildfire Threat Index (SAWTI), and field observations. SDG&E uses the following operating conditions to monitor wildfire potential and make decisions: Normal, Elevated. Extreme, and Red Flag Warning (RFW) when high winds and low relative humidity is forecasted over a long period of time. SDG&E also uses Recloser Protocols with sensitive setting functionality. In an elevated or higher condition, all distribution reclosing functions are disabled on circuit located within the High Fire Threat District (HFTD). Fire coordination efforts include contracts for wildfire prevention and ignition suppression services, Contract Fire Resources (CFR), from mid-June through the end of November and a full-time Industrial Fire Brigade (IFB) which is available 24-hours a day, as well as a year-round aerial firefighting program to support the fire agencies in its service territory.

Inspection Plan: SDG&E exceeds the basic requirements of CPUC General Order (GO) 165 and performs patrols to inspect its electric distribution system in all areas on an annual basis. In addition to distribution system patrols, detailed inspections are performed at a minimum every 3 – 5 years, with Quality Assurance / Quality Control (QA/QC) detailed inspections in HFTD Tier 3 areas conducted on a 3-year cycle. Wood pole intrusive inspections are performed depending on the age and condition of the pole and prior inspection history. For transmission system inspections, visual and infrared overhead inspections are conducted annually and detailed overhead inspections are conducted on a 3-year cycle. Substation inspections are CPUC-mandated and while they are conducted primarily for reliability, they have incidental wildfire mitigation benefits.

System Hardening Plan: SDG&E proposes to consistently evaluate, with consultation with vegetation management, environmental services, and construction services, changes and improvements to its physical assets that could be made to harden the system against wildfire risks. SDG&E has programs underway to strengthen and modernize its system: Design and Construction Standards, Testing and Deployment of Emerging Technologies, Facility Analysis, Oversight of Activities in Rural Areas, Asset Management, Overhead Transmission and Distribution Fire Hardening, Underground Circuit Line Segments, Cleveland National Forest Fire Hardening, Fire Risk Mitigation, Pole Risk Mitigation and Engineering, Expulsion Fuse Replacement, Hotline Clamps, Wire Safety Enhancement, Covered Conductor, Fire Threat Zone Advanced Protection, LTE Communication Network Automated Reclosers, Power Safety Shut OFF Engineering Enhancements, Pole Replacement Reinforcement, and Back Up Power for Resilience.

Vegetation Management Plan: SDG&E has designed and actively maintains a Vegetation Management Program aimed at keeping trees and brush clear of electric power lines. SDG&E's vegetation management program involves several components such as: tracking and maintaining a database of trees and poles that are located close to electric infrastructure; regular patrolling and tree pruning/removal, pole brushing/clearing, training first responders in electrical and fire awareness, and red flag operations. In response to the ongoing and increasing threat of wildfire risk throughout the region, SDG&E will take steps to enhance its vegetation management program to further mitigate wildfire risk in the HFTD, including increasing tree trim scope to a 25 feet clearance where feasible between trees and electric facilities.

Situational Awareness Protocols: In early 2018, SDG&E established a Fire Science and Climate Adaptation (FS&CA) department comprised of meteorologists, community resiliency experts, fire coordinators, and project management personnel to strategize for the ever-changing utility industry's fire preparedness activities and programs. Weather conditions are monitored in near-real time on a network owned and operated by SDG&E of over 175 weather stations that are physical located on electric distribution and transmission poles and which provide temperature, humidity, and wind observations every ten minutes. SDG&E also owns four high-performance computing clusters that are used to generate high quality weather data that is incorporate directly into operations. In addition, SDGE utilizes a total of 107 cameras that enhance situational awareness around wildfire.

Public Safety Power Shut-Off (PSPS) Protocols: Any decision by SDG&E to de-energize circuits for public safety is made in consultation with SDG&E's Emergency Operations Center (EOC), Meteorology, and Electric System Operations leadership. SDG&E proactively contacts customers with the potential to be affected by a PSPS through its Enterprise Notification System (ENS) by sending outbound messages though phone, email and text. These messages typically increase in urgency as the certainty of a PSPS approaches. SDG&E's call center, social media, and website provide ongoing and available resources for communication and education for SDG&E's overall customer base and conducts ongoing education campaigns about wildfire and other emergency preparedness. Additional engagement with medical baseline customers and priority essential services providers is also outlined.

Alternative Technologies: SDG&E has identified new technologies and strategies aimed at reducing the probability of ignition event. These technologies are to be used for SDG&E's proposed plans to monitor operating conditions, and different areas in their system hardening plans. SDG&E has proposed to use more advanced distribution overhead reclosers, technologies to improve electric reliability and public safety, more advanced fault clearing equipment, and more advanced technologies such as microprocessor-based relays with phasor measurement capabilities, automation controllers, sectionalizing capabilities, line monitors, direct fiber lines, and radios.

SDG&E Wildfire Mitigation Plan 2019 Cost Estimates

Table 22 summarizes the cost estimates filed February 6, 2019 in SDG&E's WMP for proposed 2019 activities, and conversion of the estimates to revenue requirement.[129] These costs are not reflected in their entirety in 2019 rates, however, for illustrative purposes, rate and bill impacts reflect these cost estimates as if cost recovery were to take place in 2019.[130] Actual cost recovery will occur in 2020 and later. Bill impact estimates as a result of this 2019 cost recovery illustrative presentation are based on proposed cost estimates that have not been approved by the CPUC.

Category	2019 Plan Cost ($000)[131]		Conversion to Revenue Requirement ($000)	
	Capital	**O&M Expense**	**Capital**	**O&M Expense**
Operational Practices	-	8,900	-	8,900
Inspection Plan[132]	-	-	-	-
System Hardening Plan	175,950	6,750	19,137	6,750
Vegetation Management Plan	-	3,630	-	3,630
Situational Awareness Protocols	1,600	2,000	174	2,000
Public Safety Power Shutoff Protocols	600	2,500	65	2,500
Sub-Total	**178,150**	**23,780**	**19,376**	**23,780**
Total	**201,930**		**43,156**	
Residential Rate Impact			**$0.0030**	
Monthly Residential Bill Impact			**$1.28**	

Table 22: SDG&E Proposed 2019 WMP Cost Estimates

SDG&E's 2019 WMP cost of $202 million is estimated to have an incremental rate impact on the residential class of $0.0030/kWh and an incremental monthly bill impact of $1.28.[133] While all three IOUs show substantial estimated costs in the System Hardening category, SDG&E shows significantly lower estimated costs in other high cost categories such as Wildfire Safety Inspection Programs and Vegetation Management Programs. As SDG&E's efforts to mitigate the risk of

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129 O&M expenses directly translate to revenue requirement, however, capital costs reflect capital spend and must be converted to the corresponding revenue requirement. Capital is converted to revenue requirement by applying authorized return on rate base and a factor to adjust the return on rate base to a gross revenue requirement. 2019 is considered the first year for purposes of converting capital spend to revenue requirement.

130 2019 rates may reflect certain costs approved as part of SDG&E's 2016 GRC proceeding. 2019 rates reflect 2018 revenue requirement as SDG&E's Test Year 2019 GRC is still pending.

131 All plan categories presented with cost ranges in SDG&E's plan. The mid-point of the range is presented.

132 SDG&E's plan states that because transmission-related activities are regulated by the Federal Energy Regulatory Commission (FERC), SDG&E has only included cost estimates for those activities that are CPUC jurisdictional.

133 For basic assumptions of the calculated impacts, see SB 695 Report section, "Incremental Revenue Requirement Customer Rate and Bill Impacts." Rate and bill impact figures presented here do not take into account how the revenue requirement will be recovered (e.g. through the distribution rate component for all customers, or some other recovery mechanism).

wildfires and enhance grid resilience began over a decade ago after San Diego experienced some of the most destructive wildfires in the county's history,[134] SDG&E's WMP costs are anticipated to be relatively lower than for the other two IOUs.

All costs associated with SDG&E's 2019 WMP are considered incremental for purposes of evaluating the potential cost implications of measures proposed in the plan; however, approximately $143.6 million in costs were included in the 2016 GRC and are already reflected in the current revenue requirement. Removal of $143.6 million that is already in the revenue requirement from the total plan costs results in an adjusted total of $58.3 million not yet in the revenue requirement. Table 23 summarizes the 2019 adjusted cost estimates adjusted downward to present only costs not yet in the revenue requirement, conversion of the estimates to revenue requirement, and the resulting residential rate and monthly bill impacts for the WMP proposed by SDG&E.

Category	2019 Plan Cost Not Yet in the Revenue Requirement ($000)[135]		Conversion to Revenue Requirement ($000)	
	Capital[136]	**O&M Expense**	**Capital**	**O&M Expense**
Operational Practices	-	500	-	500
Inspection Plan[137]	-	-	-	-
System Hardening Plan	49,150	4,440	5,346	4,440
Vegetation Management Plan	-	3,630	-	3,630
Situational Awareness Protocols	600	-	65	-
Public Safety Power Shutoff Protocols	-	-	-	-
Sub-Total	**49,750**	**8,570**	**5,411**	**8,570**
Total	**58,320**		**13,981**	
Residential Rate Impact			**$0.0010**	
Monthly Residential Bill Impact			**$0.42**	

Table 23: SDG&E Proposed 2019 WMP Cost Estimates (Not Yet in Revenue Requirement)

The costs in SDG&E's Wildfire Mitigation Plan reflect forecasted total capital costs and incremental expense in SDG&E's 2016 GRC Phase I filing,[138] pending 2019 GRC Phase I filing,[139] and other

134 *See* SDG&E's WMP, p. 1.

135 All plan categories presented with cost ranges in SDG&E's plan. The mid-point of the range is presented.

136 Capital costs are presented using total cost i.e. not incremental cost.

137 SDG&E's plan states that because transmission-related activities are regulated by the Federal Energy Regulatory Commission (FERC), SDG&E has only included cost estimates for those activities that are CPUC jurisdictional.

138 A.14-11-003 approved in D.16-06-054. SDG&E presents costs relative to its 2016 GRC filing as its 2019 GRC is pending.

139 A.17-10-047. SDG&E presents approximately $38 million in capital costs and $3 million in expenses for anticipated recovery in its 2019 GRC.

costs.[140] SDG&E states it will seek recovery for its WMP incremental costs in the appropriate procedural forum.

5. Natural Gas

Background and Status

The CPUC regulates the natural gas utility services of more than ten million customers served by Pacific Gas &Electric, Southern California Gas, San Diego Gas & Electric and several smaller utilities. Statute requires that the CPUC: 1) evaluate the reasonableness of rates and rate changes; 2) provide advice on core transport agent (CTA) rules[141] and certificates of public convenience; and 3) oversee the adoption of standards for bio-methane production. This mandate is reflected in ongoing activities in formal rate case, cost allocation, bio-methane pilot project and safety-oriented proceedings.

Natural gas utility costs are generally addressed in GRC proceedings and are composed of core procurement costs, gas system operations and customer service costs, and public purpose programs costs. Unlike the process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Core gas procurement costs are recovered in utility gas procurement rates which are adjusted monthly resulting in monthly price changes in customer bills. By doing so, the impact of price variation affects current ratepayers as opposed to future ratepayers. The figures below for PG&E, SoCalGas, and SDG&E reflect the authorized revenue requirement by rate component forecast on January 1 of each year.[142]

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[140] SDG&E filed AL 3333-E to establish the Fire Risk Mitigation Memorandum Account (FRMMA). No costs are being recorded in the FRMMA as the AL is pending approval. SDG&E anticipates recording approximately $11.8 million in capital costs and $5.6 million in expenses in the FRMMA.

[141] Core transport Agents (CTAs) procure gas for core customers such as residential and small commercial customers as an alternative to the utility

[142] All data is from 2016 – 2019 IOU responses to Energy Division SB 695 Report data requests. More detailed descriptions of how gas utility revenue requirements are determined can be found in the 2018 AB 67 Report (filed April 2019), available on the CPUC website (http://www.cpuc.ca.gov/General.aspx?id=6442460031).

PG&E Revenue Requirement by Rate Category

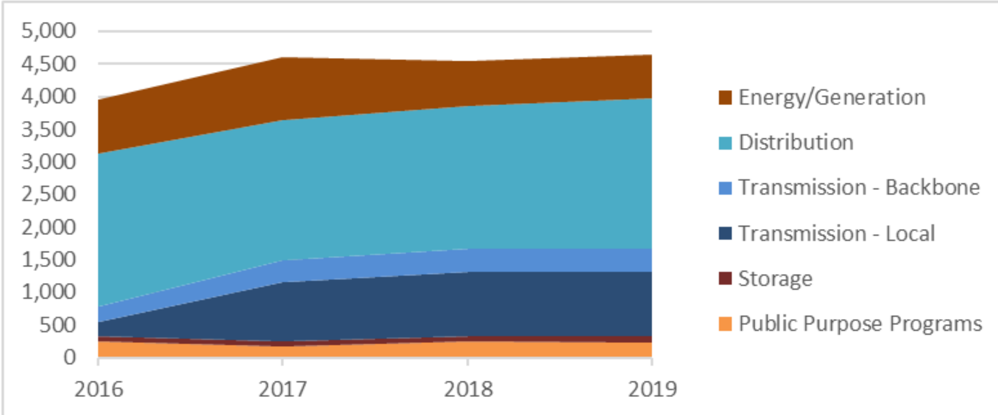

Figure 17: 2016 – 2019 PG&E January 1 Revenue Requirement, by Rate Category ($ millions)

PG&E's gas revenue requirement has increased by approximately 19% since 2016, with about a 3% increase from 2018 to 2019.[143] Distribution costs comprised the largest proportion of the 2018 – 2019 revenue requirement increase, principally due to a rise in the utility's authorized GRC revenue requirement to fund programs such as maintaining the safety of its distribution pipelines[144] and the collection of greenhouse gas emission reduction program costs, which the utility began recovering in mid-2018. PG&E's costs for procuring gas have decreased about 20% since 2016, with about a 2% decrease from 2018 to 2019.

SoCalGas Revenue Requirement by Rate Category

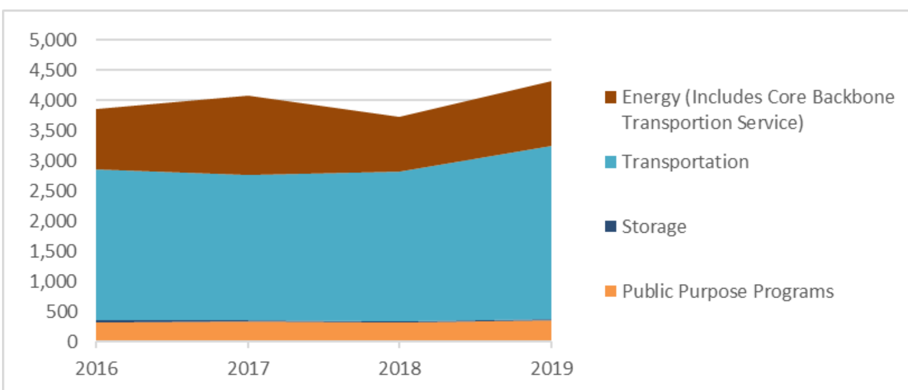

Figure 18: 2016 – 2019 SoCalGas January 1 Revenue Requirement, by Rate Category ($ millions)

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[143] PG&E's 2019 transmission revenue requirement proposed in A.17-11-009 was pending authorization on January 1, 2019, and is not included.

[144] Distribution pipeline safety program costs include costs for upgrading an aging pipeline system and to improve emergency response capabilities.

Since 2016, SoCalGas' gas revenue requirement has increased by about 12%, with about a 16% increase from 2018 to 2019. The transportation costs, both transmission and distribution, comprise the largest portion of the 2018 – 2019 revenue requirement increase. The principal reason for the increase was the collection of greenhouse gas emission reduction program costs which the utility began recovering from ratepayers beginning in 2018, though some additional costs are also attributed to the Pipeline Safety Enhancement Plan and the methane leak abatement program. In addition, the relatively warm winter of 2017-2018 resulted in decreased usage and required the utility to increase its rates in 2018 to adjust for the decreased revenue from 2017.

SDG&E Revenue Requirement by Rate Category

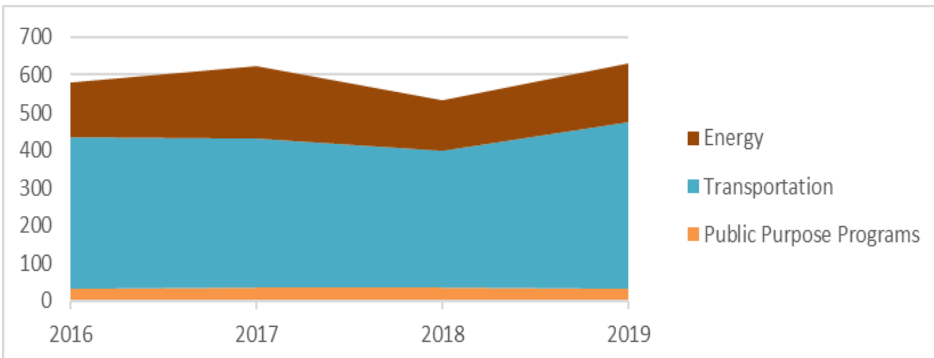

Figure 19: 2016 – 2019 SDG&E January 1 Revenue Requirement, by Rate Category ($ millions)

SDG&E's gas revenue requirement has increased by approximately 9% since 2016, with about an 18% increase from 2018 to 2019. Transportation costs comprise the largest proportion of the cost increase. Principal reasons for the increase are costs associated with the greenhouse gas emission reduction program and a collection of balancing accounts amortized in 2018 and 2019, including the accounts for the Pipeline Safety Enhancement Plan and the Mobile Home Park Pilot Program.

Activities and Proceedings in the Upcoming 12-Months (May 1, 2019 – April 30, 2020)

PG&E Application to Revise its Gas Rates and Tariffs

In September 2017, PG&E filed an application[145] to revise its cost allocation and rate design for its distribution revenue requirement. Among the utility's proposals are to base its cost allocation methodology on historical, embedded costs rather than use the marginal cost to serve customers; to increase its minimum monthly gas transportation charge from $3 to $15 for typical non-CARE residential customers; and to establish a higher $45 minimum charge for non-CARE residential

[145] A.17-09-006.

customers that consume high quantities of gas. Additionally, the gas throughput forecast PG&E will use to set rates is being considered in the proceeding as well. The Commission has not issued a final decision on these issues yet.

In D.18-10-040, issued in A.17-09-006, the Commission adopted a settlement agreement to implement the objective of Senate Bill 711 to minimize gas bill volatility for residential customers. The decision revised PG&E's baseline quantities to establish a peak winter season so that residential customers bills will be less volatile during the high gas demand months of December and January.

PG&E Test Year 2019 Gas Transmission and Storage Rate Case

In November 2017, PG&E filed an application[146] to set its revenue requirement and rates for the utility's gas transmission and storage system for 2019 through 2021. For 2019, PG&E is requesting the Commission to approve a revenue requirement of $1.48 billion, a $180 million increase from 2018. The work that the funding would be used for includes hydrotesting the utility's pipelines to ensure that they can withstand operating pressure, upgrading pipelines so that they can be inspected using advanced in-line inspection devices to measure wall strength, and implementing new gas storage regulations adopted by the Department of Oil, Gas, and Geothermal Resources.

PG&E has also proposed in the proceeding to significantly reconfigure its gas storage system. The utility seeks to close two existing gas storage facilities, Los Medanos and Pleasant Creek, and to substantially reduce the capacity of MacDonald Island, its largest gas storage facility. The impact of this proposal on the reliability of PG&E's gas system and its ability to serve its customers is a key consideration. The application is currently pending, and the Commission will evaluate PG&E's proposals to ensure they are just and reasonable and in the public interest. A final decision in the proceeding has not been issued yet.

SoCalGas and SDG&E Application to Recover Costs for PSEP 2

On September 2, 2016, Southern California Gas (SoCalGas) and San Diego Gas & Electric (SDG&E) filed an application[147] to recover recorded costs attributed to implementation of the Pipeline Safety Enhancement Program (PSEP) Phase II (D.14-06-007). On February 21, 2019, the Commission approved the recovery of costs attributed to the implementation of the PSEP which includes 26 pipeline projects, 15 bundled valve projects and two methane sensing equipment pilot projects. Decision (D.)19-02-004 authorized SoCalGas and SDG&E to recover the balance of their recorded costs in the amount of $186,532,169.

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146 A.17-11-009.

147 A.16-09-005.

SoCalGas and SDG&E Application for Revenue Requirement associated with PSEP 3

On March 30, 2017, SoCalGas and SDG&E filed an application[148] for a new revenue requirement associated with PSEP for completion of 12 pipeline projects. SoCalGas and SDG&E forecast the costs to be $197.5 million in capital expenditures and $57 million in Operations and Maintenance expenses, resulting in a cumulative forecasted 2019 revenue requirement of $45 million for SoCalGas and $562,000 for SDG&E. The application was approved on March 28, 2019.

SoCalGas and SDG&E Application for Revenue Requirement associated with PSEP 4

On November 13, 2018, SoCalGas and SDG&E filed an application[149] for reasonableness review of PSEP costs for 44 pipeline projects and 39 bundled valve projects. SoCalGas and SDG&E state that they have spent approximately $854 million in capital expenditures and $86.7 million in Operations and Maintenance expenses, resulting in the associated revenue requirement of $188 million for SoCalGas and $23 million for SDG&E. The application is currently under preliminary evaluation by the Commission.

SoCalGas and SDG&E Test Year 2019 General Rate Case

On October 2, 2017, SoCalGas and SDG&E each filed an application[150] to set their revenue requirement and rates for the utilities' cost of providing gas and electric service for 2019 through 2020. For 2019, SoCalGas is requesting to increase the gas transportation and storage revenue requirement by $2.9 billion. SDG&E is requesting a total of $2.2 billion ($435 million for gas and $1.764 billion for electric) for costs in 2019. The Commission is currently reviewing the proposals to ensure they are just and reasonable and in the public interest. A decision is expected in 2019.

SoCalGas and SDG&E Application to Revise Rates for Gas Services

On July 31, 2018, SoCalGas and SDG&E filed their Triennial Cost Allocation Proceeding (TCAP). Cost allocation is the process of allocating the utilities' authorized revenue requirement to utility functions and customer classes, which include residential customers, small commercial and industrial customers, medium and large commercial and industrial customers, electric generators, and wholesale customers. The TCAP also addresses gas storage-related proposals related to managing the reliability of the natural gas system. In this proceeding, SoCalGas and SDG&E also propose to update their baseline allowances per SB 711. PU Code Section 739 requires the Commission to make efforts to minimize bill volatility for residential customers by modifying the length of baseline

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148 A.17-03-021.

149 A.18-11-010.

150 A.17-10-007 & A.17-10-008.

seasons or defining additional base seasons. SoCalGas' and SDG&E's current baseline allowances have been in effect since 2002. The application is currently under review with a decision expected at the end of 2019.

Order Instituting Rulemaking (OIR) to Reduce Natural Gas Leakage

On June 12, 2017, the Commission approved Phase I[151] for the Natural Gas Leak Abatement Program, adopting best practices and reporting requirements in consultation with the California Air Resources Board (ARB), pursuant to Senate Bill (SB) 1371.[152] According to Public Utilities Code Section 977(d), the Commission shall consider "the impact on affordability of gas service for vulnerable customers as a result of incremental costs of compliance with the adopted rules or procedures." Consistent with the statute, the decision acknowledged that given numerous unknowns associated with a new program, there is not enough quantifiable information to evaluate the cost effectiveness of the program. The 2018 and 2019 associated costs are forecasted to be $66 million for PG&E, $234 million for SoCalGas, and $12.3 million for SDG&E. Going forward, the utilities are expected to incorporate associated program costs into their General Rate Case proceedings. Phase II of the rulemaking will address the future of a cost-effectiveness framework, the ratemaking treatment of Lost and Unaccounted for Gas, and potential changes to reporting requirements.

OIR to Implement Dairy Bio-Methane Pilots

Pursuant to SB 1383 (Lara, 2016), the Commission opened a rulemaking[153] to establish dairy bio-methane natural gas pipeline injection demonstration projects. In 2018, the Commission along with the Air Resources Board and the Department of Food and Agriculture, put forth a pilot solicitation and selected six projects for construction. Contracts between utilities and developers of the six pilot projects have been signed and are under review at the Commission. Construction on these projects should take approximately two years for interconnection to occur. The pilots will undergo evaluation processes to determine GHG reduction levels and project goal attainment. Forecasted costs associated with the six pilot projects are estimated to be approximately $318 million.

OIR to Update Natural Gas Pipeline Injection Standards

In response to SB 840 (Budget 2016), a rulemaking[154] reopened in July 2018 to update natural gas pipeline injection standards based on the report published by the California Council on Science and Technology. The Commission is currently evaluating whether to modify natural gas pipeline

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[151] R.15-01-008.

[152] Public Utilities Code Sections 975, 977, 978.

[153] R.17-06-015.

[154] R.13-02-002.

injection heating value and siloxane standards. Because gas utilities have different ways of managing their pipelines, for the purpose of streamlining and removing risk for renewable natural gas project developers, the Commission is looking into the development of a standardized renewable natural gas interconnection tariff for the state. In addition, the Commission is looking to investigate natural gas pipeline injection and storage standards for green hydrogen.

OIR to Identify Disadvantaged Communities in the San Joaquin Valley

On March 26, 2015, the Commission opened a rulemaking[155] to implement PU Code Section 783.5 (AB 2672). The Commission was directed to analyze the economic feasibility of certain energy options including: (a) extending natural gas pipelines; (b) increasing existing program subsidies to residential customers; and (c) other alternatives that would increase access to affordable energy. The Phase I decision adopted the methodology for identification of communities meeting the statutory definition of a San Joaquin Valley Disadvantaged Community under Section 783.5. Phase II of the rulemaking adopted D.18-12-015 which approved $56 million in funding for 11 pilots with PG&E and SCE as the Pilot Administrators for the electrification pilots and SoCalGas administering a natural gas pilot project in California City[156] with limited gas pilots in Allensworth and Seville.

OIR to Evaluate Mobile Home Park Pilot Program and Adopt Programmatic Modifications

On April 26, 2018, the Commission opened a rulemaking[157] to evaluate the Mobile Home Park Pilot Program, a three-year pilot program adopted in D.14-03-021 to incentivize mobile home parks and manufacture housing communities with master-metered natural gas and electricity service to convert to direct utility service. Collectively, California IOUs (PG&E, SCE, SoCalGas, SDG&E, Southwest Gas and CalPeco Electric) have recorded approximately $90,000 in the first two years of the pilot. The rulemaking will consider whether to extend or expand the program or transition it to a permanent utility program.

SoCalGas Application to Sell Renewable Natural Gas

On February 2, 2019, SoCalGas filed an application[158] for an opt-in green gas tariff for customers to voluntarily purchase a renewable gas alternative. The application is currently under preliminary evaluation by the Commission. In addition, SoCalGas and PG&E have both begun renewable natural gas procurement pilot program for use at the compressed natural gas pumps operated by the utilities.

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155 R.15-03-010.

156 SoCalGas is authorized to recover $5,641,100 for administering the gas pilot for California City.

157 R.18-04-018.

158 A.19-02-015.

6. Conclusion

California policies addressing climate related risks, safety needs, infrastructure replacement planning, and dynamic grid and market changes carry a high price tag for ratepayers and must be carefully managed. Despite the urgency with which we must address our environmental objectives, the pace of regulatory change must be balanced with our responsibility to keep rates fair and reasonable. Perhaps the greatest value in tracking and identifying essential legislative program cost information is in the increased transparency into the ramifications of the numerous decisions it makes annually that affect the affordability of service. Program budgets, along with illustrative rate and bill impacts, can be viewed in isolation or examined cumulatively in terms of the costs and savings associated with priority resource investments. Furthermore, as our rate impact modeling evolves, this report aims to provide the Commission, Legislature, the Governor, and the public with a clear framework for evaluating the potential costs of California's clean energy mandates, grid optimization, and safety needs. Armed with this information, energy industry stakeholders and leaders can better understand policy tradeoffs, address safety and affordability risks, and more effectively implement change.

Appendix

The following weblink to the Commission's Energy Division Retail Rates webpage contains links to the reports submitted by PG&E, SCE, SDG&E, and SoCalGas, pursuant to Public Utilities Code Section 913.1: http://www.cpuc.ca.gov/General.aspx?id=6442461186