



UTILITY COSTS AND AFFORDABILITY OF THE GRID OF THE FUTURE:

An Evaluation of Electric Costs, Rates, and Equity Issues
Pursuant to P.U. Code Section 913.1

MAY 2021



California Public
Utilities Commission

UTILITY COSTS AND AFFORDABILITY OF THE GRID OF THE FUTURE

AN EVALUATION OF ELECTRIC COSTS, RATES AND EQUITY ISSUES
PURSUANT TO P.U. CODE SECTION 913.1

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UTILITY COSTS AND AFFORDABILITY OF THE GRID OF THE FUTURE

I. EXECUTIVE SUMMARY

Senate Bill (SB) 695 (Kehoe, 2009) requires the CPUC to prepare an annual report addressing electric and gas cost and rate trends as well as actions to limit or reduce utility costs.¹ For 2021, the CPUC is taking a different approach to this report in order to provide a longer-term rate forecast and to leverage a wider array of subject matter expertise from within the CPUC as well as externally in academia and the energy industry. The goal is to evaluate longer term system costs and policy risks. The draft of this report (the SB 695 Report or White Paper) laid the foundation for an “En Banc Meeting on Cost and Rate Trends” held on February 24, 2021, which provided a venue for discussing potential options for addressing the trends and impacts identified herein.

The CPUC faces multiple intersecting policy mandates that require a delicate balance to avoid unintended consequences. If handled incorrectly, California’s policy goals could result in rate and bill increases that would make other policy goals more difficult to achieve and could result in overall energy bills becoming unaffordable for some Californians. Electrification goals and wildfire mitigation planning are among the near-term needs, for example, that place upward pressure on rates and bills.

Another regulatory risk that has been identified in prior SB 695 reports and is further detailed in this white paper is a continuing increase in capital investments that are recovered in rate base by the investor-owned utilities (IOUs). While capital investments by IOUs will be necessary to meet California’s energy and climate policy goals, they can result in higher bills for customers. Evaluating the reasonableness of these investments in a cleaner, more efficient grid raises affordability and equity implications that merit further investigation.

While this white paper does not explore a comprehensive, detailed breakout of all essential cost categories and their incremental impacts on IOU rates, it evaluates select areas of projected costs of specific programs and policy priorities, including transportation electrification (TE) and wildfire mitigation plan (WMP) implementation. The decision to highlight these specific areas of cost is informed by recent findings of staff analysis and the desire to bring their relative impacts on overall rate forecasts into sharper focus within the broader operations and revenue requirements of California’s IOUs. The figures below provide the

¹ 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 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases.”

illustrative impacts of projected wildfire spending relative to the other major bundled² residential rate components from 2021 through 2030.³

Figure ES-1: PG&E Forecasted Bundled Residential Rates (\$ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate

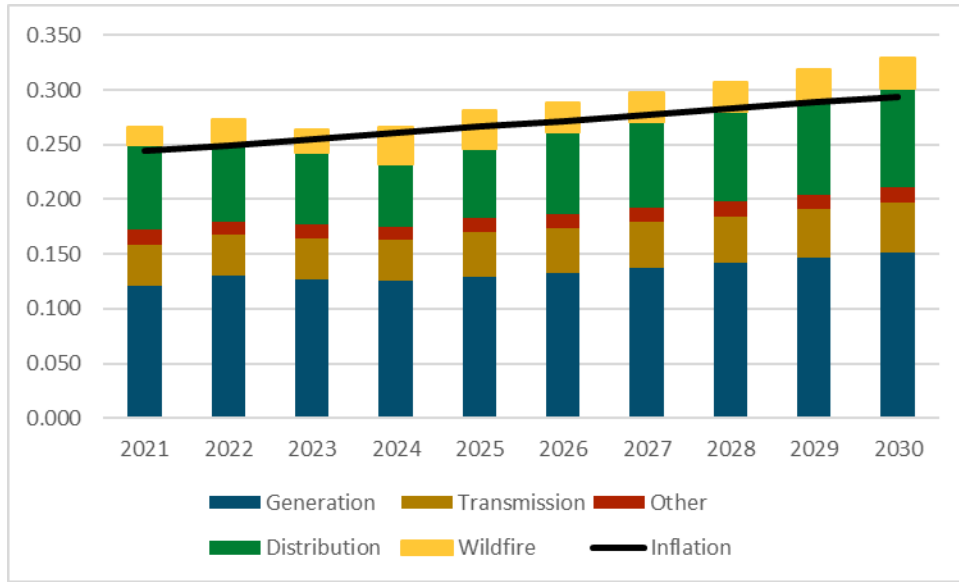
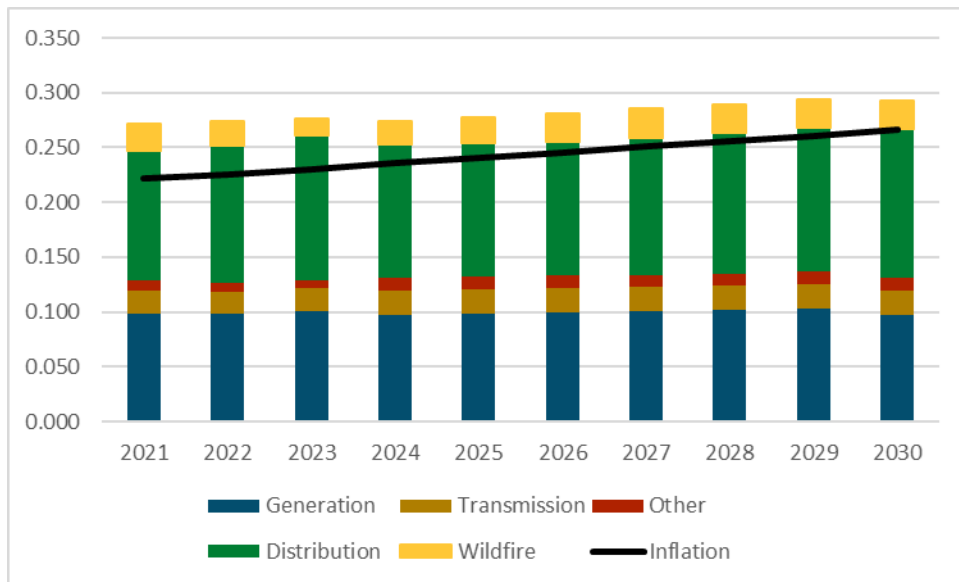


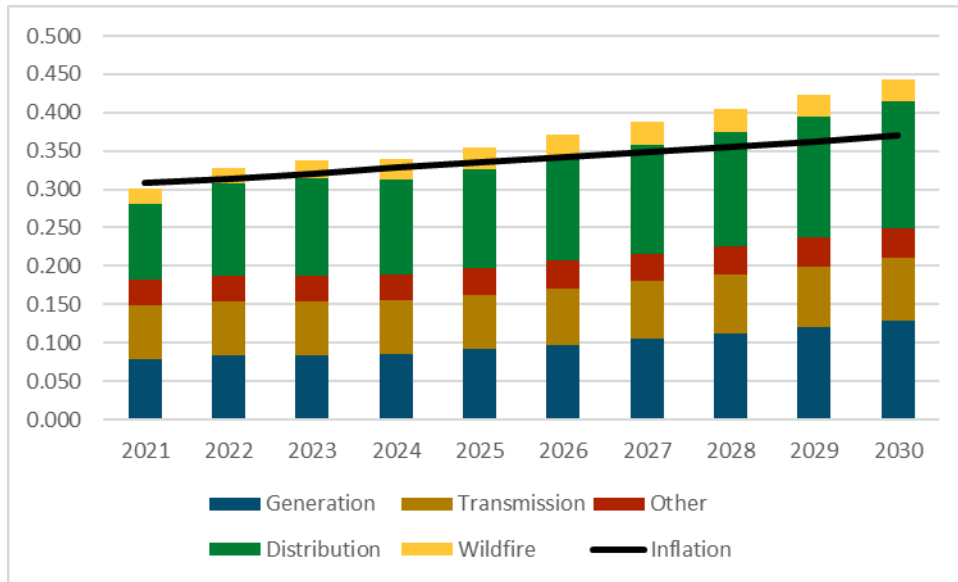
Figure ES-2: SCE Forecasted Bundled Residential Rates (\$ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



² Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

³ The inflation-adjusted forecasted rate line is based on 2020 actual rates. The rates in Figures ES-1 through ES-3 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

Figure ES-3: SDG&E Forecasted Bundled Residential Rates (\$ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



The rate forecasts developed as part of this white paper, in conjunction with estimates of natural gas rates and gasoline prices, were used to project total energy bills for a representative high energy usage household located in a hot climate zone based on rates for each of the major IOUs, as presented in the figures below. These projections show that, for energy price sensitive households, bills are expected to outpace inflation over the coming decade. The implication is that, if household incomes are expected to generally increase at the rate of inflation, energy bills will become less affordable over time.

Figure ES-4: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on PG&E Rates

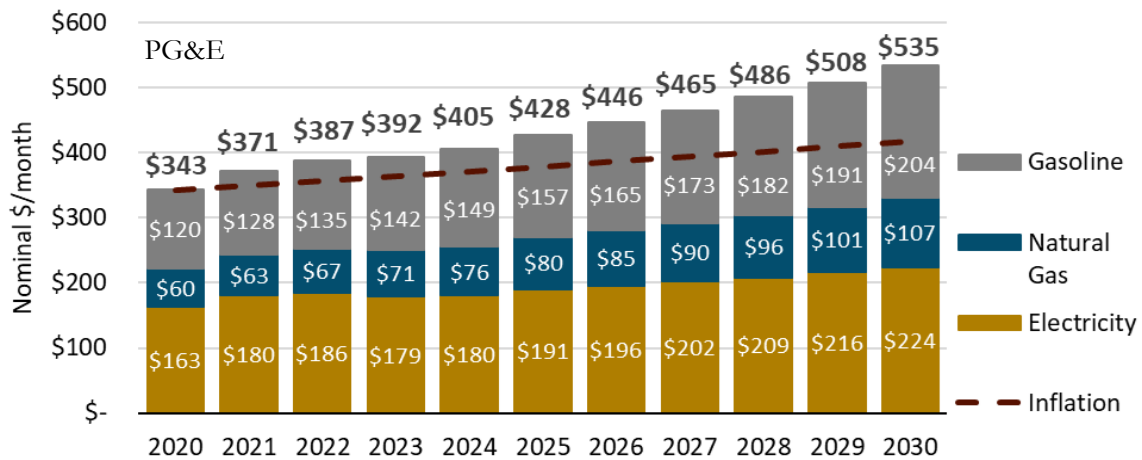


Figure ES-5: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SCE/SoCalGas Rates

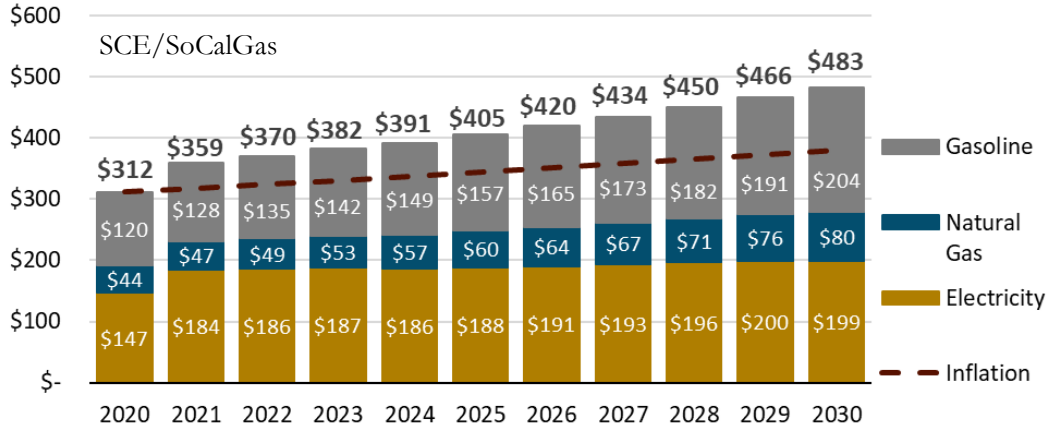
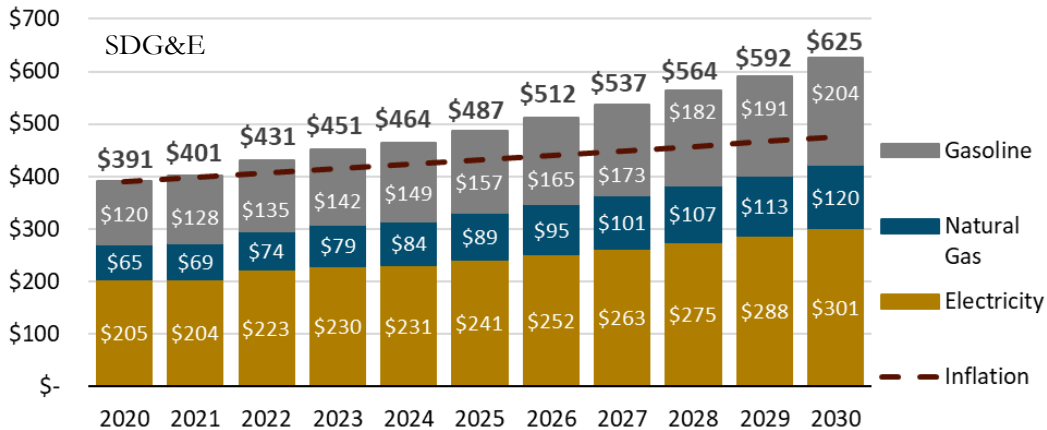


Figure ES-6: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SDG&E Rates



The policy goals and regulatory requirements that create upward cost pressures appear manageable over a longer time horizon, but if not managed correctly, they could trigger equity and affordability concerns for vulnerable customer populations over the short- to mid-term horizon. There is the potential for a growing divide in the cost of service between customers participating in behind-the-meter (BTM) or distributed energy resources (DER) and those who are less likely to do so. Moderate- to higher-income customers are more likely to invest in DERs such as solar photovoltaic (PV) systems, electric vehicles (EV), and storage technologies, and the advanced rate offerings that support them. This enables them to shift load and take advantage of potential structural billing benefits, which often results in a cost shift onto lower-income and otherwise vulnerable customers. Without the prudent management of IOU revenue requirements, rate base,

rate structures, and DER incentives, California’s continued progress toward the optimized grid of the future may widen this chasm between participants and non-participants of DER opportunities.

There are three critical and overlapping regulatory fronts that must be actively managed to address this fundamental equity risk for vulnerable customers:

1. The costs and timing of fulfilling clean energy and electrification mandates;
2. The relatively rapid pace of rate base growth; and,
3. Revenue shifts to lower-income non-participants from Net Energy Metering (NEM) and other DER incentives.

PROBLEM STATEMENT

The need to improve the safety and reliability of the electric system while meeting California’s climate goals and various statutory mandates will require careful management of rate and bill impacts to ensure that electric services remain affordable. As California continues transitioning to a more robust distributed energy resources marketplace with greater deployment of electric vehicles, it will be essential to employ aggressive actions to minimize growth in utility rate base and to protect lower-income ratepayers from cost shifts and bill impacts. This white paper explores the affordability of the grid of the future and is intended to stimulate discussion of potential solutions that will be necessary to ease this transition, particularly for California’s most vulnerable customers.

KEY FINDINGS

Across all three IOUs since 2013, rates have increased by 37% for PG&E, 6% for SCE, and 48% for SDG&E.⁴ The growth in rates can be largely attributed to increases in capital additions driven by rising investments in transmission by PG&E and distribution by SCE and SDG&E. While the utilities have made major financial commitments to wildfire mitigation and transportation electrification, these costs have not been fully reflected in rates so far. This paper finds that transportation electrification investments are not expected to contribute to significant rate growth in the near term, but that wildfire mitigation efforts will. Furthermore, higher than national average returns on equity (ROE) are a more modest but not insignificant factor that has amplified the three IOUs’ revenue growth in recent years.

While tracking rates is important, customers care more about their bills than rates. California bills have typically been lower than most of the country in recent years, but those trends are changing. In 2019, SDG&E’s bundled residential average monthly bill ranked 142nd highest out of about 200 IOUs, even though its rate was among the top 20 highest. PG&E, however, is showing a 2018 and 2019 monthly bill ranking of 94th highest and 70th highest, respectively, meaning PG&E’s bills are higher than most of the IOUs being ranked. Further, SCE’s bills, while still lower than the median (#100 ranking), moved up in the rankings from 136th highest to 122nd highest between 2018 and 2019.

⁴ Bundled system average rate. Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU. These increases on an average annual basis from 2013 to 2020 are about: PG&E 5.3 percent; SCE 0.8 percent; SDG&E 6.8 percent.

Looking forward, the paper’s 10-year baseline forecast shows steady growth in customer rates (nominal \$/kWh) between 2020 and 2030 for the three IOUs:

- PG&E: \$0.240 to \$0.329, or about an annual average increase of 3.7 percent
- SCE: \$0.217 to \$0.293, or about an annual average increase of 3.5 percent
- SDG&E: \$0.302 to \$0.443, or about an annual average increase of 4.7 percent

By 2030, bundled residential rates are forecasted to be approximately 12 percent, 10 percent, and 20 percent higher, respectively, than they would have been if 2020 actual rates for each IOU had grown at the rate of inflation.⁵ However, when the analysis focuses on households in the hotter regions of the state, household bills (electric, natural gas, and gasoline) are forecasted to rise at an annual rate of 4.5 percent, as compared to a 1.9% inflation rate.

While the cost to further reduce GHG emissions in the electric sector to 38 million metric tons (MMT) compared to a target of 46 MMT would increase bills by \$4 to \$9 a month, a well-managed effort to move customers to all electric homes and electric vehicles could result in over a \$100 a month reduction in overall energy bills. This means that, in order to avoid large increases in energy bills, customers will need to adopt technologies that require large up-front investments. In the absence of subsidies and low-cost financing options, this could create equity concerns for low- to moderate-income households and exacerbate existing disparities in electricity affordability.

ORGANIZATION

The remainder of this white paper is organized as follows:

- **Section II:** A foundational review of *historical* trends in costs, rates, and bills with a focus on longer-term, capital-related costs and impacts on bills from clean energy programs, and statutory mandates that have historically resulted in additional ratepayer costs are presented.
- **Section III:** An evaluation of cost and rate *projections* with a particular focus on two areas: transportation electrification and wildfire mitigation costs. In addition, this section highlights affordability concerns and distributional equity in low to moderate income households.
- **Section IV:** Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b).
- **Section V:** Conclusion.
- **Addenda:** Critical addenda are included on natural gas cost and rate trends as well as summaries of En Banc panelist discussions and stakeholder comments on this white paper.

⁵ 2020 rates are actual rates in effect at yearend 2020; if 2020 rates were to increase at the rate of inflation (approximately 1.9% per year), rates in 2030 would be: PG&E 0.294; SCE 0.266; SDG&E 0.370. Inflation is approximately 1.9% per year.

II. HISTORICAL COST AND RATE TRENDS

2.1 Section Summary

In past years, the SB 695 Report has provided a historical review of IOU revenue requirements at the functional area of utility operations⁶ level to illustrate the major drivers of electric cost and rate growth. This functional-level revenue requirement review, generally presented as a percentage change in the generation revenue requirement, distribution revenue requirement, etc., is a high-level view of overall trends; the review does not quantitatively analyze underlying cost data that may categorically⁷ form part of historical General Rate Case (GRC) costs or stand-alone⁸ program costs.

For the 2021 SB 695 Report embodied in this white paper, transportation electrification and wildfire-related costs are highlighted as potential cost drivers.⁹ Both of these cost categories involve capital costs i.e., investment in IOU infrastructure, prompting a discussion of the IOUs' continually increasing capital investments. While IOU capital investments (generally known as "rate base") will be necessary to meet California's policy goals, balancing major investments in a cleaner, more efficient grid while sustaining affordable rates is more challenging as IOU rate base grows.

In keeping with past SB 695 Reports, rates and bills for the bundled¹⁰ residential customer class are highlighted in this white paper. Compared to IOUs in the rest of the country, California IOUs Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) bundled residential rates are higher than most while bills are lower than most. For 2018 and 2019,¹¹ bundled residential electric rates for PG&E and SDG&E customers increased faster than the rate of inflation. SDG&E's residential rates in particular have seen increases in recent years due to departing load as a result of high rates of solar adoption. Further, bundled residential and small business customers generally have higher average rates than the bundled system average and bundled large industrial and agricultural customers generally have lower average rates.¹²

Across all three IOUs, rate base is increasing, meaning that net capital additions have been outpacing depreciation of existing assets. The growth in rate base has been driven by rising transmission investments for PG&E and distribution investments for SCE and SDG&E. This rise in rate base has been coupled with a growth of solar adoption, which in turn has led to residential costs being shifted from customers who have

⁶ Functional areas of utility operations include generation, distribution, etc.

⁷ Some of these categories could broadly fall under Safety, Affordability (reasonable rates), Reliability, and Clean Energy, with potentially other subcategories of analytical interest, such as Wildfire Mitigation (i.e. Safety) and Transportation Electrification (i.e. Clean Energy).

⁸ Stand-alone here means not included in a GRC or Energy Resource Recovery Account (ERRA) proceeding. Stand-alone costs can include legislative policy program costs such as those in the "Legislative Policy Program Costs" sub-section.

⁹ A functional area of utility operations revenue requirement review was not performed, but rather, specific cost categories were selected for further examination; Electrification goals and wildfire mitigation planning are among the near-term needs that may place upward pressure on rates and bills.

¹⁰ Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

¹¹ 2019 is the most recent year for which national-level data is available.

¹² All other things being equal, a class average rate is generally higher than the system average rate when the class in question contributes a higher proportion of revenue requirement relative to the system average and to other classes.

installed rooftop solar to customers who have not.¹³ The result is that growing electric rates have been offset to some extent for NEM customers, who are disproportionately older homeowners in high-income areas, while non-NEM customers have shouldered some of the cost of maintaining the grid. In addition, continued adoption of other distributed energy resources (storage, EVs, etc.) and advanced rate offerings that promote improved load management may add to costs shifted to non-participating customers. However, this requires a deeper examination of the long-term savings and benefits to the system of a more efficient grid with greater penetration of behind-the-meter (BTM) resources.

This section also considers the impact that transportation electrification (TE) programs, wildfire mitigation-related costs, and Federal Energy Regulatory Commission (FERC) transmission costs have had on electric rates. The analysis found:

- TE programs have had little impact on bundled residential rates, and the TE portion of forecasted bundled residential rates is not expected to grow significantly in the near-term.
- Historical experience with wildfire mitigation-related costs is largely based on SDG&E, since SDG&E's experience with wildfire spending precedes that of the other two IOUs; despite a decade of spending on wildfire mitigation, SDG&E's wildfire costs have continued to increase, which may indicate what is in store for PG&E and SCE.
- FERC transmission revenue requirements have increased significantly over the past few years in a number of categories.¹⁴

California Utilities Compared to the Rest of the U.S.

California leadership in advancing clean energy policy in the United States must be considered in any discussion of both past and future rates and bill trends:

- The state's per capita energy consumption is the fourth lowest in the nation, due in part to California's mild climate but more importantly due to a commitment to energy efficiency.¹⁵
- California ranks first in the nation as a producer of electricity from solar, geothermal, and biomass resources and fourth in the nation in conventional hydroelectric power generation.¹⁶
- California has the most operating utility-scale battery storage capacity in the nation at over 200 MW, about twice as much as the installed capacity of the state with the next largest amount.¹⁷

¹³ The cost shift results in shifts in revenue requirements among different customer groups.

¹⁴ Transmission revenue requirements have risen a total of 38.1 percent over the period from 2016 to 2021 across the three IOUs.

¹⁵ See U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates <https://www.eia.gov/state/print.php?sid=CA> (last updated January 16, 2020, accessed January 5, 2021).

¹⁶ *Id.*

¹⁷ See EIA bar graph, "U.S. operating utility-scale battery storage by state (top 10, March 2019)" <https://www.eia.gov/todayinenergy/detail.php?id=40072> (accessed January 5, 2021).

- About one-fourth of the nation’s electric vehicle charging stations are in California.¹⁸
- California leads the nation in installed flexible distributed energy resource capacity of 4.7 GW, or one tenth of statewide grid demand, and may have up to 13.5 GW by 2025.¹⁹

Many of these efforts have resulted in a cleaner electricity portfolio but have also led to declines in electricity sales due to energy efficiency, energy conservation, and customer generation of electricity. Declines in electricity sales have had the effect of raising electric rates as fixed costs are spread over a smaller usage base.

Historically, the bundled Residential Average Rates (RAR) of the California IOUs have been higher than those of most United States IOUs.²⁰ Table 1 shows for 2018 and 2019²¹ the simple volumetric bundled residential average rate for PG&E, SCE, and SDG&E, compared to approximately 200 total IOUs nationally, ranked from highest rates (#1 ranking) to lowest rates (#200 ranking). For example, in 2019 SDG&E’s bundled residential average rate ranked 17th highest out of about 200 IOUs.

However, while rates are an important measure of the cost of providing electricity, looking at actual bills provides a clearer picture of affordability. California IOU bundled residential customer bills have generally been lower than about half of all U.S. IOUs, as shown by the rankings. For example, in 2019 SDG&E’s bundled residential average monthly bill ranked 142nd highest out of about 200 IOUs, even though its rate was among the top 20 highest. PG&E, however, is showing a 2018 and 2019 monthly bill ranking of 94th highest and 70th highest, respectively, meaning PG&E’s bills are higher than most of the IOUs being ranked. Further, SCE’s bills, while still lower than the median (#100 ranking), moved up in the rankings from 136th highest to 122nd highest between 2018 and 2019.

Table 1: U.S. IOU Ranking of PG&E, SCE, and SDG&E, Bundled Residential Average Rates and Monthly Bills (2018, 2019)

U.S. IOU Ranking – Highest to Lowest (out of approximately 200 IOUs)				
	Bundled Residential Average Rate		Bundled Residential Average Monthly Bill	
	2018	2019	2018	2019
PG&E	15	24	94	70
SCE	31	42	136	122
SDG&E	9	17	108	142

¹⁸ See U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates.

¹⁹ See “Unlocking California’s Gigawatt-Scale Distributed Energy Potential”, Greentech Media, September 22, 2020. Available at: <https://www.greentechmedia.com/articles/read/unlocking-californias-gigawatt-scale-distributed-energy-potential>

²⁰ “Higher than most” is the same as “higher than the median,” or “higher than half of the items being ranked.” In other words, because the ranking is from highest to lowest, the lower the ranking number, the higher the rate or bill.

²¹ 2019 is the most recent year for which national-level data is available. See U.S. Energy Information Administration (U.S. EIA) https://www.eia.gov/electricity/sales_revenue_price/, Table 6.

2.2 Historical Trends in Electric Rates and Bills

Electric rates measure price per kilowatt hour paid by electric customers, and historical rate trends allow comparison of how an IOU's rates track another metric, inflation, over time. The reason inflation is typically used as a benchmark for electric rate growth is because it has traditionally been assumed that household incomes rise at about the rate of inflation, thus if electric rates increase at the same rate then the affordability of electric service should remain unchanged for the average household.²²

Bundled System Average Rate

Rates may be viewed at system level for all customer classes or at customer class level, such as residential class level. **Bundled System Average Rate (SAR)** is a high-level measure of an IOU's authorized bundled²³ customer revenue requirement expected to be recouped through authorized forecasted sales to bundled customers.

$$\text{Bundled SAR} = \frac{\text{Bundled customers authorized revenue requirement (\$)}}{\text{Bundled authorized forecasted sales (kWh)}}$$

Figure 1 through Figure 3 show each IOU's nominal rates in the color-shaded portion of the figure, with the IOU's inflation-adjusted rates shown by the black line. Nominal rates trending below the black line indicate that the IOU's bundled SARs are tracking favorably to inflation-adjusted rates. Nominal rates trending above the black line indicate that the IOUs' bundled SARs are increasing higher than the rate of inflation.

²² Rates are tracked from the base year 2012 by applying the Consumer Price Index (CPI) to the previous year's bundled SAR to show inflation-adjusted bundled SAR. CPI reported by the U.S. Department of Labor, Bureau of Labor Statistics, West Region, All Items, All Urban Consumers (not seasonally adjusted). 2020 CPI data reflects 11 months of data.

²³ Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

Figure 1: PG&E Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

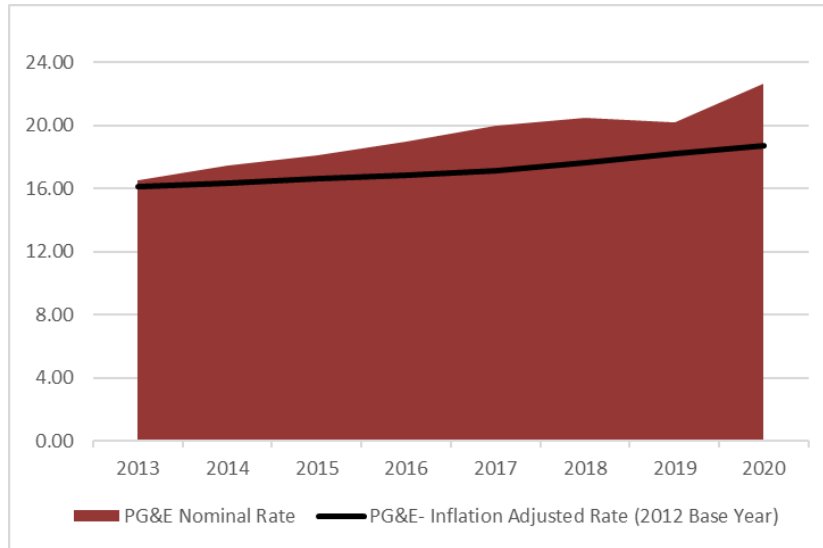


Figure 2: SCE Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

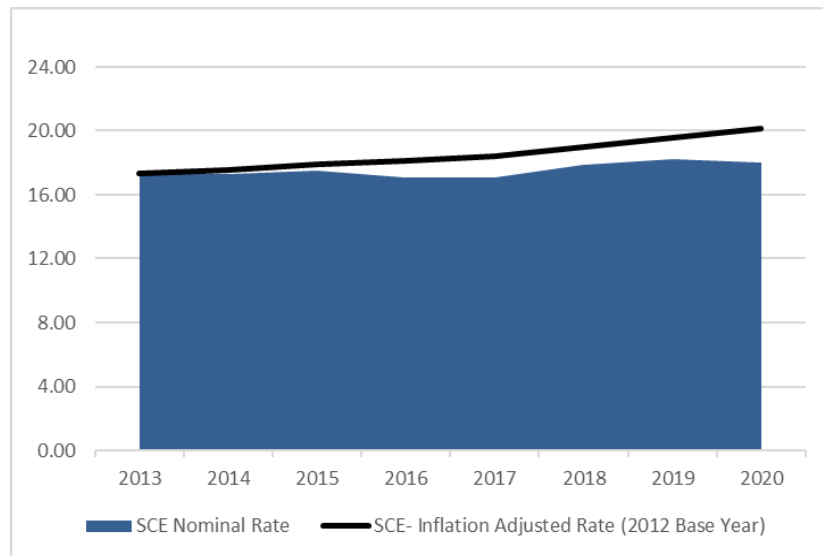
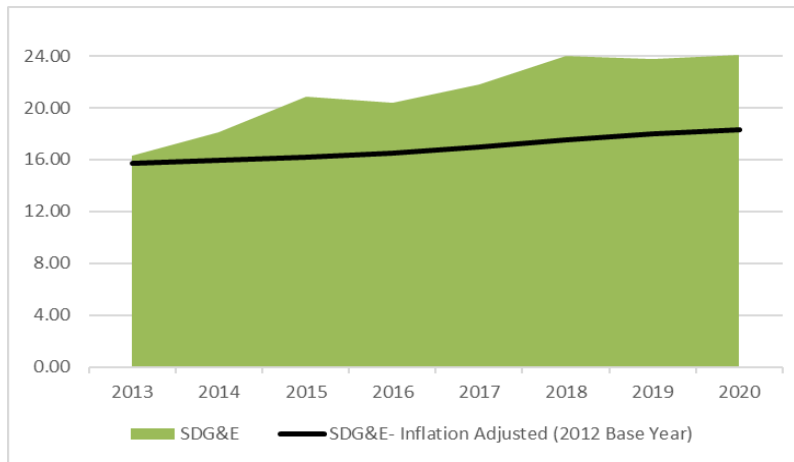


Figure 3: SDG&E Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1



The variance in Figure 3 between SDG&E’s inflation-adjusted SAR and its nominal SAR may be due to the effect of diminishing kWh sales. SDG&E has a larger share of customers investing in rooftop solar compared to PG&E and SCE. This high rate of photo-voltaic (PV) adoption affects the denominator (kWh sales) of SDG&E’s bundled SAR, as customers are purchasing less electricity from the utility, although they may still be consuming the same amount from their PV system. While the decreased demand from the utility allows it to avoid some costs of procuring generation, a utility still has fixed costs that cannot be fully eliminated. As a result, declining utility sales result in larger rate increases as utility fixed costs are now spread across fewer units of usage.

Bundled System Average Rate by Customer Class

A breakdown of the bundled system average rate by customer class is shown for each IOU in Figure 4 through

Figure 6. Each class shows the same upward trend as the system average rate over this period, with the residential and small business customers generally having higher average rates than the system average and the large industrial and agricultural customers generally having lower average rates.

Figure 4: PG&E Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1

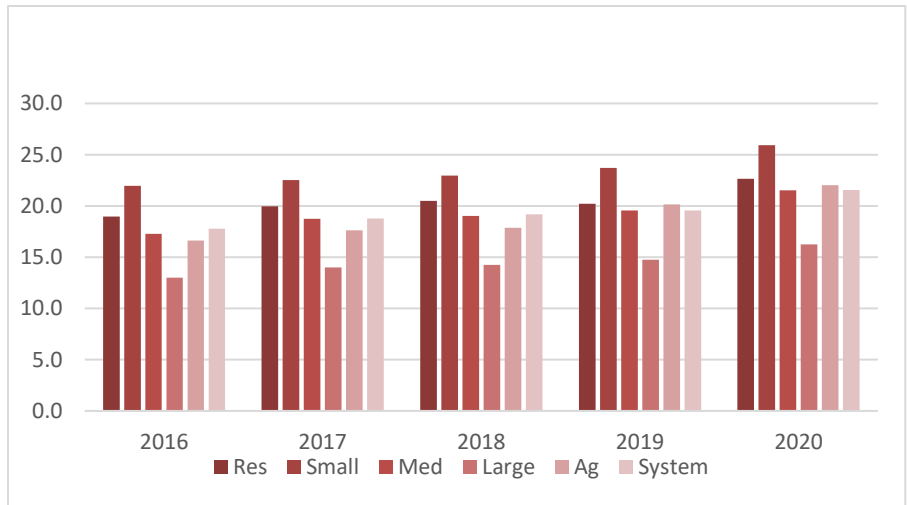


Figure 5: SCE Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1

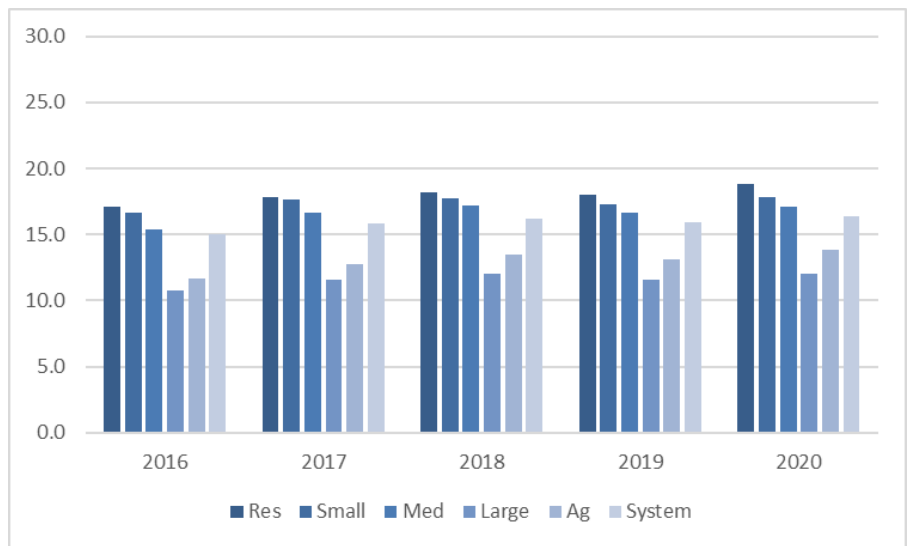
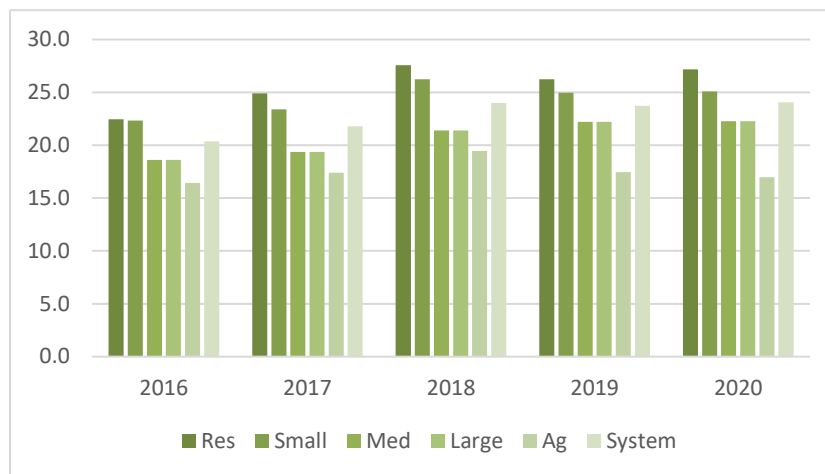


Figure 6: SDG&E Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1



Residential and Select Small Commercial Bundled Average Monthly Bills

The major determinant in calculating bills is electricity **usage**.²⁴ Residential usage tends to cluster around typical usage profiles, which vary by climate zone.²⁵ However, typical load profiles for non-residential customers can vary substantially, depending on their usage patterns in the commercial, industrial, or agricultural customer class.²⁶ Nevertheless, small business customers may be grouped by commercial customer group using standard industry codes such as the North American Industry Classification System (NAICS) in order to get a sense of typical usage for customers with the same industry code.²⁷ Figure 7 through Figure 9 show for each IOU typical bundled average monthly bills for residential customers²⁸ as well as for commercial customers representing Food Services and Drinking Places (NAICS 722), Ambulatory Health Care Services (NAICS 621), and Real Estate (Property Management, NAICS 531).²⁹ Bundled small business customers with industry subsector code Food Services (NAICS 722) show typical average monthly bills in the mid- to high triple-digits.³⁰

²⁴ Usage (in kWh) multiplied by a rate factor equals the volume of electricity billed. Other bill elements such as fixed charges and taxes are outside the scope of this analysis.

²⁵ For residential, usage includes electricity consumption (kWh). For this analysis, average monthly usage for each IOU is based on average monthly usage reported for bill impacts presented in bill inserts.

²⁶ For non-residential, usage may include electricity consumption (kWh) or demand (kW). Demand usage is outside the scope of this analysis.

²⁷ Grouping by industry code does not definitively determine typical usage profiles as several other factors such as climate zone, size of establishment, age of establishment, and energy efficiency of equipment may significantly affect usage.

²⁸ Residential customers not enrolled in the California Alternate Rates for Energy CARE (Non-CARE). Lower-income residential customers enrolled in the CARE program receive up to a 35 percent discount on bills.

²⁹ See U.S. Bureau of Labor Statistics for more information about NAICS subsector codes. These NAICS subsector codes were selected by the IOUs as being representative of small commercial customers and are not exhaustive for the customer class.

³⁰ Typical average monthly bills are for illustrative purposes only.

Figure 7: PG&E Typical Bundled Average Monthly Bills (\$/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1

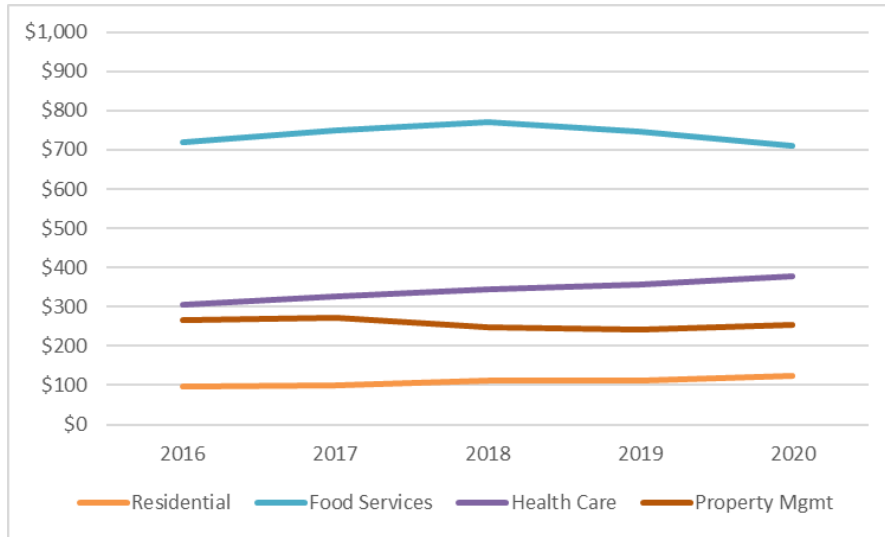


Figure 8: SCE Typical Bundled Average Monthly Bills (\$/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1

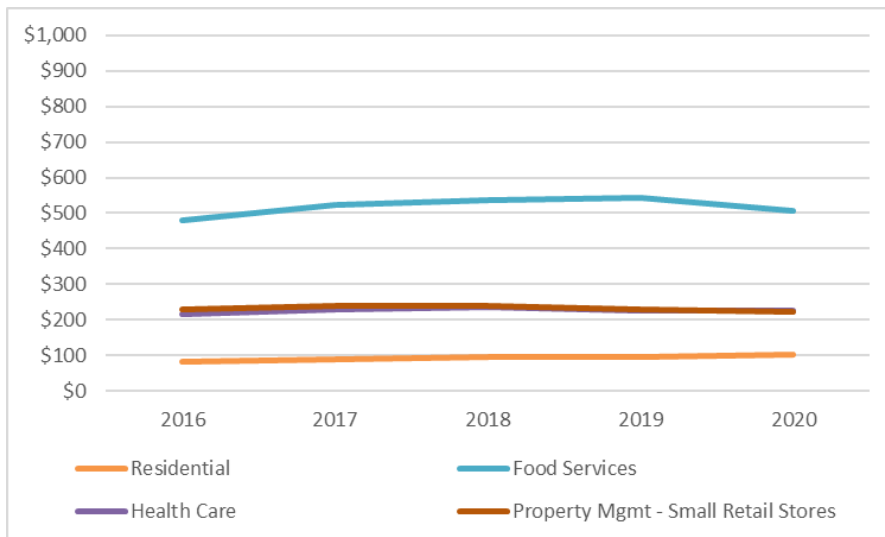
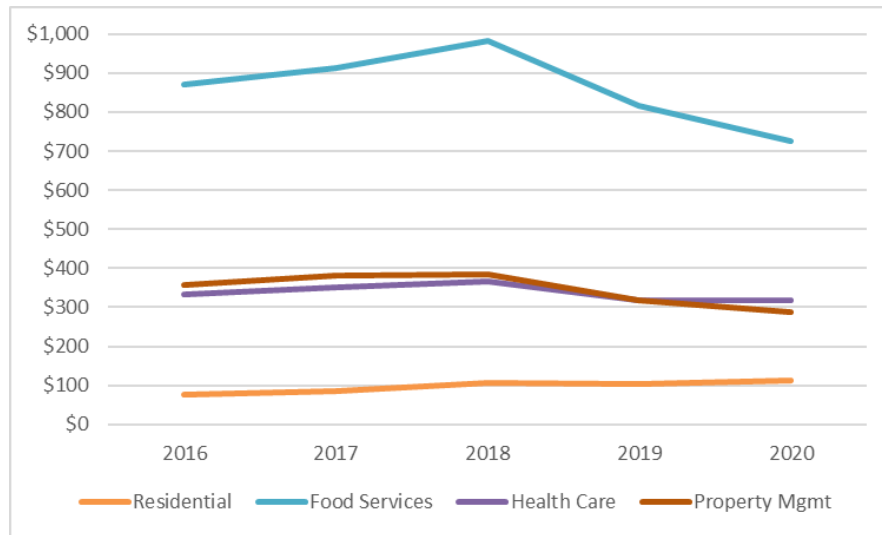


Figure 9: SDG&E Typical Bundled Average Monthly Bills (\$/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1



2.3 Historical Utility Costs and Transparency

Capital Costs and Capital-Related Revenue Requirements

The CPUC annually issues the *California Electric and Gas Utility Cost Report*, also known as the Assembly Bill (AB) 67 Report, which publishes the costs to ratepayers of all utility programs and activities currently recovered in retail rates.³¹ These costs are presented at the **authorized** revenue requirement level, which is the level at which costs go into rates. Recorded costs authorized for recovery during ratesetting proceedings include both **capital expenditures** and **operations and maintenance (O&M)** expenses, both of which must be converted to revenue requirement as part of rates implementation.

Operations & Maintenance Expenses

O&M expenses are generally passed-through to ratepayers without profit markup and are recovered from ratepayers on a dollar-for-dollar basis with no amortized cost recovery over time, meaning the utility earns no profit on O&M expenses and recovers those costs in the same year they were incurred. These expenses include all labor and non-labor expenses for a utility’s operation and maintenance of its generation plants and distribution and transmission systems. O&M expenses also include general and administrative expenses such as personnel costs and purchased materials and services.

³¹ The 2019 AB 67 Report is available at: <https://www.cpuc.ca.gov/General.aspx?id=6442460031> . The most recently available year of this report is 2019.

Capital Expenditures

The utility earns profits on capital expenditures, and capital expenditures are recovered over a long period of time as the related asset depreciates. Because of the multi-year recovery timeframe for capital investments, the revenue requirement in any given year is a fraction of the total **capital-related revenue requirement**. This fractional approach makes conversion of capital expenditures into annual capital-related revenue requirement a complicated process, and limits the transparency of the full costs that ratepayers will pay over time for capital expenditures. For example, if the utility were to spend \$1 billion in one year on wildfire mitigation costs that include both capital expenditures (e.g. undergrounding electric lines) and O&M costs (e.g. vegetation management) the rate impact in that first year would be far less than \$1 billion since only the O&M cost would be recovered in the first year, but the capital costs will be included in rates for many years and will ultimately be higher than \$1 billion since the capital investment is recovered over time and includes the utility's profits.

To understand how capital-related revenue requirement is calculated, one must first understand the concept of **rate base** which is essentially the book value of the utility's assets taking accumulated depreciation into account. Depreciation spreads the cost to ratepayers of the capital investment over the assets' useful life. The IOU's rate base is the value of the company's undepreciated assets at a specific point in time and provides a basis for computing rates of return. The measurement of rate base is dependent on two main components, net capital additions and accumulated depreciation.

$$\text{Rate Base} = \text{Net capital additions} - \text{Accumulated depreciation}$$

Thus, rate base is the amount that remains after accumulated depreciation³² is subtracted from net capital additions. When net capital additions exceed accumulated depreciation, which has generally been the case for PG&E, SCE, and SDG&E, rate base and the related capital revenue requirements increase:

$$\text{Net capital additions} > \text{Accumulated depreciation} = \text{Increase in rate base}$$

Capital-Related Revenue Requirement

Capital-related revenue requirements are comprised of **depreciation expense revenue requirement** (including related tax effects) and **return on rate base revenue requirement**:

$$\text{Capital-related revenue requirement} = \text{Depreciation expense (including related tax effects) revenue requirement} + \text{Return on rate base revenue requirement}$$

Return on rate base represents the cost to the utility of financing the capital investment, including the cost of the authorized profit, known as return on equity.³³ Depreciation expense is calculated according to the IOU's depreciation rate schedules. Return on rate base is calculated by multiplying the IOU's authorized rate of return by **rate base**:

$$\text{Return on rate base revenue requirement} = \text{Authorized rate of return (a percentage)} \times \text{Rate base}$$

³² Related tax effects are grouped with accumulated depreciation.

³³ Other costs included in return on rate base are interest on debt, which represents the cost of borrowing from a bond investor.

California IOUs' Authorized Return on Equity Has Been Above the National Average

The CPUC establishes capital structure for each utility by setting the percentages of common stock, long-term debt, and preferred stock to total capital that the utility should hold. Within each utility's capital structure, the CPUC also sets the cost of each capital component, which results in an overall cost of capital (also known as rate of return) as shown in Table 2: SCE, PG&E, SDG&E, SoCalGas Cost of Capital

Utility	Cost of Common Stock (ROE)	Cost of Long-term Debt	Cost of Preferred Stock	Overall Cost of Capital (ROR)
SCE	10.30%	4.74%	5.70%	7.68%
PG&E	10.25%	5.16%	5.52%	7.81%
SDG&E	10.20%	4.59%	6.22%	7.55%
SoCalGas	10.05%	4.23%	6.00%	7.30%

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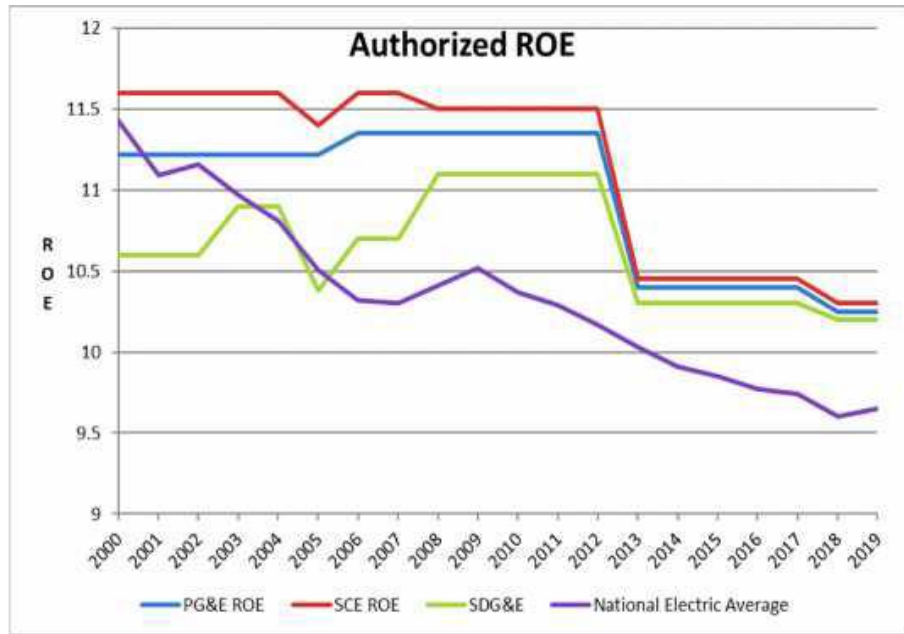
Table 2: SCE, PG&E, SDG&E, SoCalGas Cost of Capital

Utility	Cost of Common Stock (ROE)	Cost of Long-term Debt	Cost of Preferred Stock	Overall Cost of Capital (ROR)
SCE	10.30%	4.74%	5.70%	7.68%
PG&E	10.25%	5.16%	5.52%	7.81%
SDG&E	10.20%	4.59%	6.22%	7.55%
SoCalGas	10.05%	4.23%	6.00%	7.30%

The cost of common stock or return on equity (ROE) is a large component of the overall cost of capital. The CPUC sets ROE by estimating expected return on alternative investments of comparable risk in capital markets using financial models. Figure 10 shows that even though the authorized ROE for each utility declined in 2013 from previous years, the ROEs remain higher than national average ROE.

Figure 10: PG&E, SCE, and SDG&E Authorized Return on Equity, Compared to National Electric Average Return on Equity (2000 – 2019)

³⁴ Each capital component is weighted by its percentage of total capital in arriving at the overall cost of capital.



Rate Base is Increasing

Figure 11 through Figure 13³⁵ show the total annual rate base for each of the IOUs from 2016 through 2020.³⁶ Net capital additions are greater than accumulated depreciation in all figures, with corresponding increases in rate base. Increases in rate base over time result in higher depreciation expense revenue requirement and return on rate base revenue requirement as depreciation and return on rate base are now being calculated over an increasing base amount. Rate base has been increasing on average by approximately 5 percent per year for PG&E, 8 percent per year for SCE, and 7 percent per year for SDG&E since 2016, despite relatively flat load growth.³⁷

³⁵ SDG&E rate base data is from AB 67 Report data responses and does not include a breakout of net capital additions and accumulated depreciation. PG&E and SCE data are from Energy Division data responses.

³⁶ “Other” rate base (working capital, other non-fixed asset adjustments) not material and not included.

³⁷ Percentages in nominal terms. Real terms would be slightly lower to account for inflation.

Figure 11: PG&E, Total Electric Rate Base (\$000), Nominal and Inflation-Adjusted, January 1

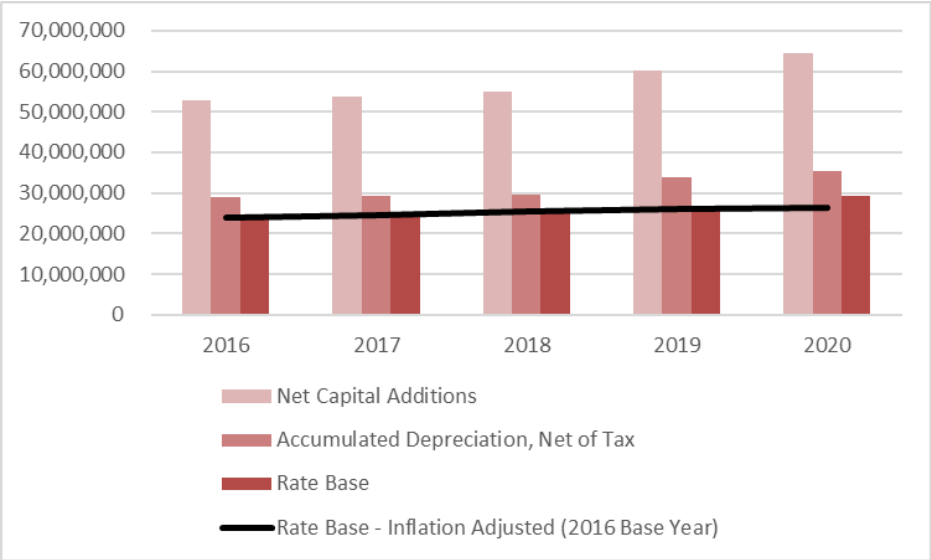


Figure 12: SCE, Total Electric Rate Base (\$000), Nominal and Inflation-Adjusted, January 1

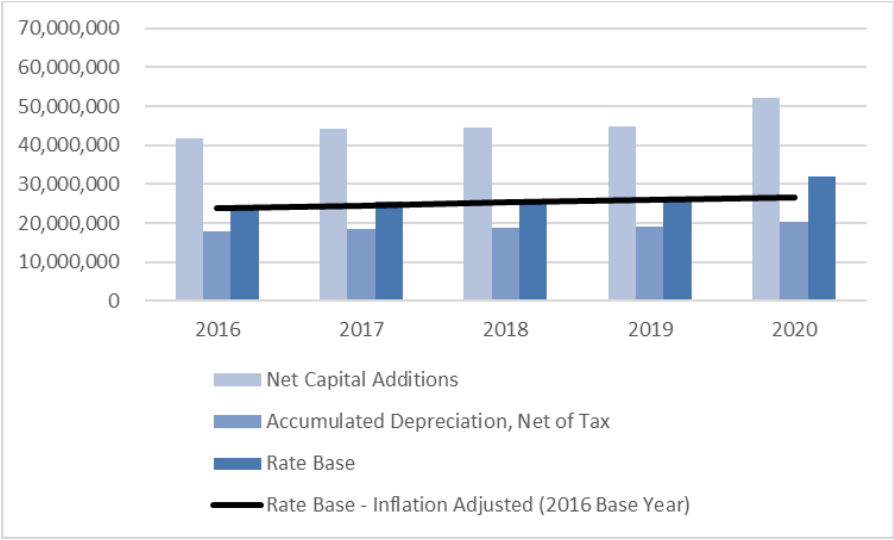
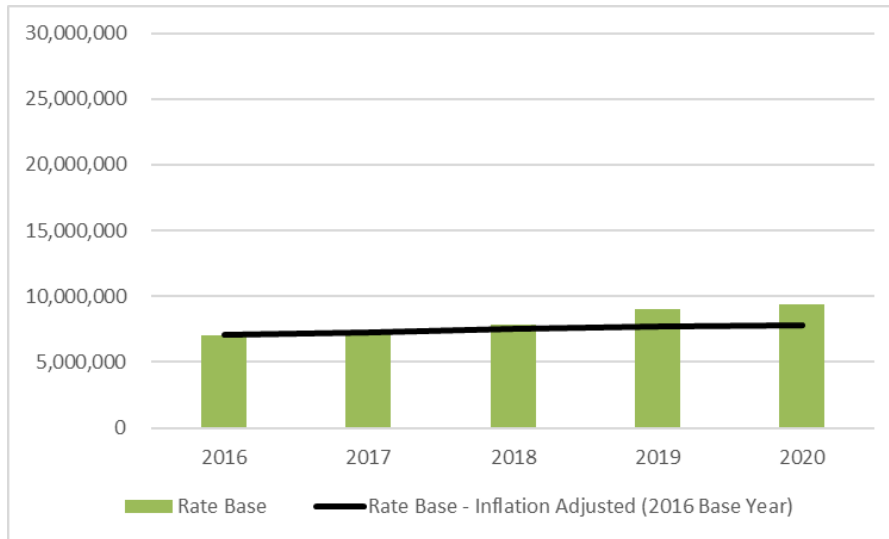


Figure 13: SDG&E, Total Electric Rate Base (\$000), Nominal and Inflation-Adjusted, January 1



A Comparison of California Utilities' and Select U.S. Utilities' Electric Net Utility Plant

Electric net utility plant data may be examined to compare PG&E, SCE and SDG&E electric rate base growth to that of other U.S. IOUs. Data obtained from the Federal Energy Regulatory Commission (FERC) Form 1 presents **net utility plant** data, which is plant-in-service³⁸ data net of accumulated depreciation.³⁹ The net utility plant data is not directly comparable with the IOU rate base data presented above.⁴⁰ However, using net utility plant data for comparison illustrates the California IOUs' net utility plant investments relative to that of other IOUs with similar bundled revenues.

Figure 14 shows 2016 - 2019⁴¹ net utility plant data for PG&E and SCE compared with five other U.S. IOUs grouped by the U.S. Energy Information Administration (EIA) 2019 bundled revenue rankings.⁴² In other words, Florida Power & Light had the highest bundled retail revenue and is ranked #1, with SCE at #2. Figure 15 similarly shows 2016 – 2019 net utility plant data for SDG&E compared with three other U.S. IOUs in the U.S. EIA 2019 bundled revenue rankings. For example, Entergy Louisiana comes in at #16 ranking and SDG&E at #17.

³⁸ Plant-in-service includes certain capital lease data as well as construction work-in-process data, among other line items.

³⁹ Accumulated amortization and depletion is reported along with accumulated depreciation.

⁴⁰ It is unknown what methodology the IOUs use for reporting plant-in-service and accumulated depreciation data to FERC.

⁴¹ FERC Form 1 data is reported at quarter and yearend. Data presented for 2016 – 2019 is as of yearend (2020 yearend data not yet available).

⁴² Bundled revenue (\$000) = Sales (MWh) x Rate (cents/kWh). Revenue data from U.S. Energy Information Administration (U.S. EIA). See https://www.eia.gov/electricity/sales_revenue_price/, Table 10 for bundled revenue data. Note: the #18 ranked utility is not an IOU and is not included in this analysis.

Figure 14: Net Electric Utility Plant, PG&E, SCE, and Five Other U.S. IOUs (\$000), Ranked by Bundled Revenue (Highest to Lowest) (2016 – 2019)

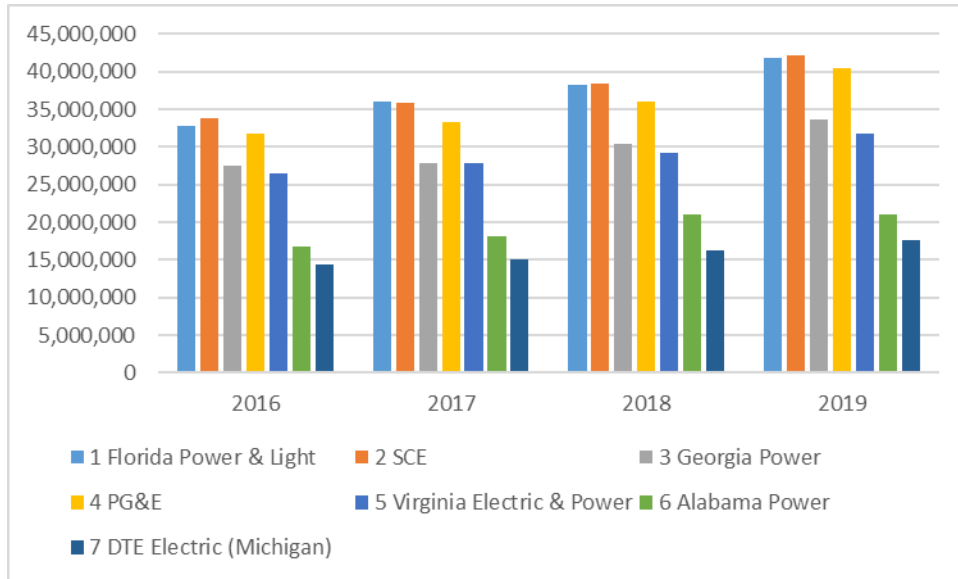
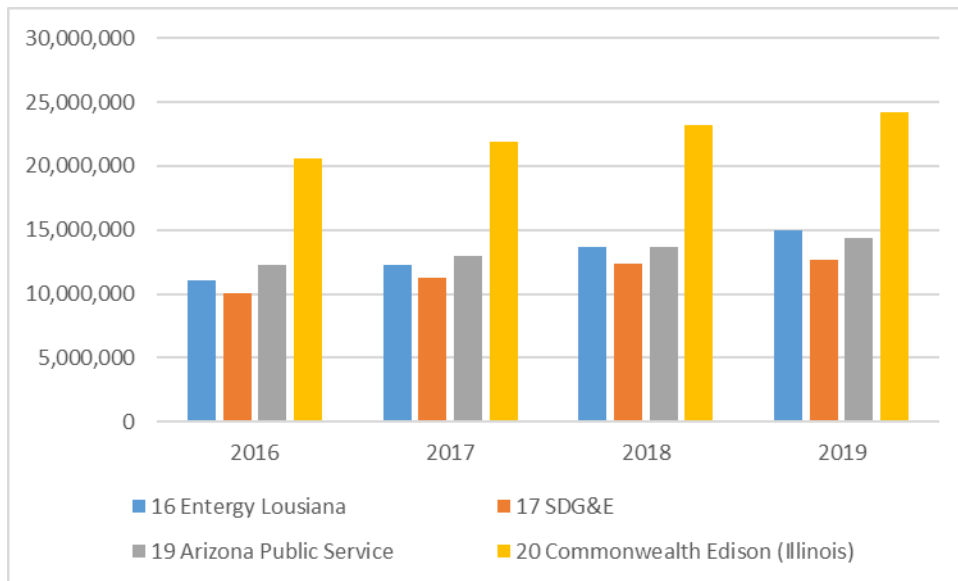


Figure 15: Net Electric Utility Plant, SDG&E and Three Other U.S. IOUs (\$000), Ranked by Bundled Revenue (Highest to Lowest) (2016 – 2019)



For the utility grouping with PG&E and SCE, all IOUs show an increase in net utility plant from 2016 to 2019. Average annual increases over this period (from highest to lowest) are: Florida Power & Light 8.5 percent; PG&E 8.4 percent; Alabama Power 8.2 percent; SCE 7.6 percent; DTE Electric 7.1 percent; Georgia Power 7.1 percent; and Virginia Electric & Power 6.4 percent. Even though SCE shows the highest

overall net utility plant over this period, its average annual increases are less than those of PG&E and two other IOUs.

The SDG&E utility grouping similarly shows an increase in net utility plant from 2016 to 2019 across all IOUs. Average annual increases over this period (from highest to lowest) are: Entergy Louisiana 10.5 percent; SDG&E 8.0 percent; Commonwealth Edison 5.6 percent; and Arizona Public Service 5.4 percent. SDG&E shows the lowest overall net utility plant over this period, however its average annual increase is the second highest compared to the three other IOUs.

Return on Rate Base Revenue Requirement is Increasing

As previously shown,⁴³ rate base has a direct relationship with the return on rate base revenue requirement that is recovered from ratepayers. The return on rate base revenue requirement reflects the opportunity for the IOU to earn a profit.⁴⁴ Return on rate base may represent a return to shareholders paid by ratepayers; however, having a set⁴⁵ rate of return ensures that IOUs are able to raise sufficient capital to make improvements to infrastructure and provide safe and reliable service to all customers. On the flip side, by having a set rate of return, IOUs are inherently incentivized to make investments to drive an increase in their rate base and therefore, their profitability.⁴⁶

Figure 16 through Figure 18⁴⁷ show for each IOU the return on rate base revenue requirement by functional category. The return on rate base revenue requirement for distribution is showing an increasing trend for SCE and SDG&E. PG&E's distribution return on rate base revenue requirement has been fairly constant, while its transmission return on rate base revenue requirement spiked in 2020, having roughly doubled since 2016.⁴⁸ Total annual return on rate base revenue requirement since 2016 grew by approximately 5 percent per year for PG&E, 7 percent per year for SCE, and 5 percent per year for SDG&E.

⁴³ See *Return on Rate Base Revenue Requirement* equation under "Capital-Related Revenue Requirement" heading.

⁴⁴ Profit is earned after the service of debt acquired to finance capital additions.

⁴⁵ Return on equity is set by the CPUC; debt-service return is determined by the bond market.

⁴⁶ This is known as the **Averch-Johnson effect**: the perception that the rate of return is higher than what the utility actually needs to ensure that shareholders continue to provide capital for investment, and the utility increases its returns to shareholders by making investments beyond the need threshold.

⁴⁷ SDG&E return on rate base data 2016 - 2018 is from AB 67 Report data responses; data for 2019 - 2020 is extrapolated from 2016 - 2018 data. PG&E and SCE data are from Energy Division data responses.

⁴⁸ This increase of about 50 percent in 2020 over 2019 is due to the implementation of Transmission Owner (TO) 20 formula rate as of January 2020.

Figure 16: PG&E, Return on Electric Rate Base Revenue Requirement (\$000), Nominal Rates in Effect January 1

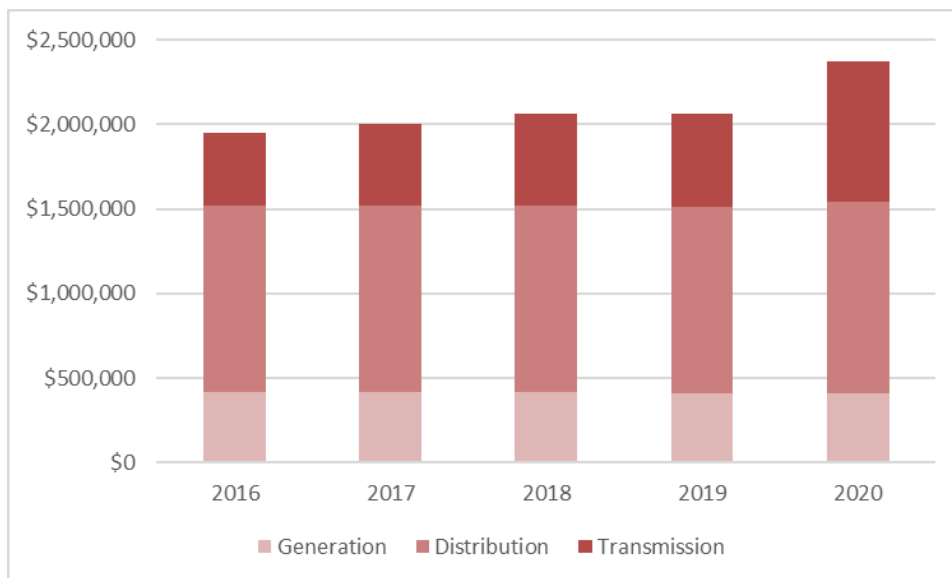


Figure 17: SCE, Return on Rate Electric Base Revenue Requirement (\$000), Nominal Rates in Effect January 1

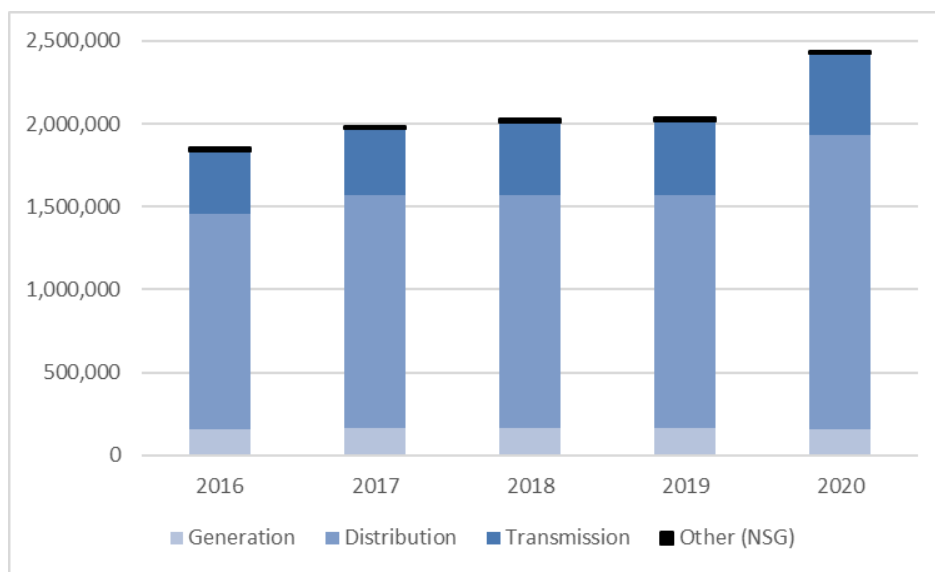
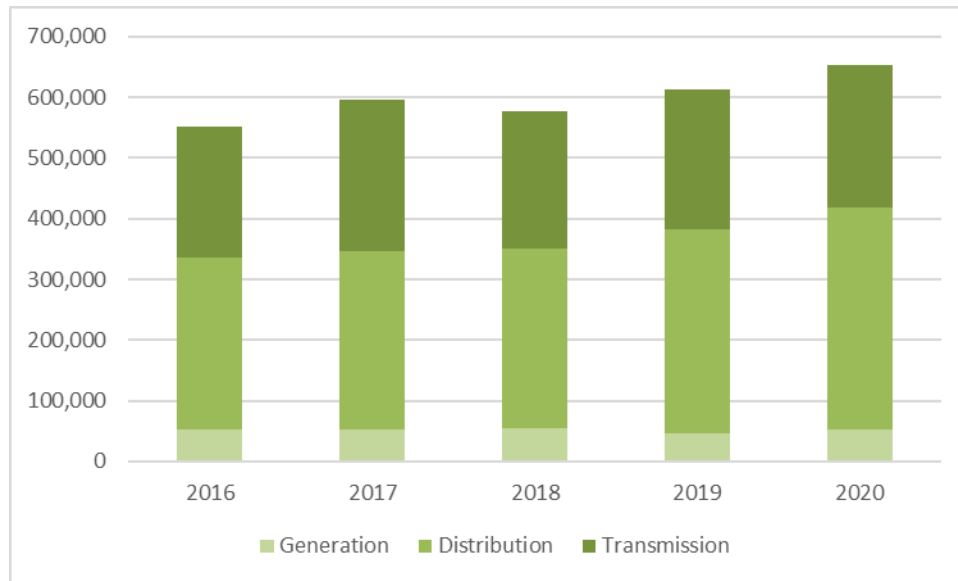


Figure 18: SDG&E, Return on Electric Rate Base Revenue Requirement (\$000), Nominal Rates in Effect January 1



IOU net capital additions, accumulated depreciation, rate base, depreciation expense (including related tax effects) revenue requirement, and return on rate base revenue requirement are reviewed in Phase I of each General Rate Case (GRC) cycle,⁴⁹ except for transmission capital additions, which are reviewed in FERC rate cases. Currently, there are no known projected rate base schedules with corresponding projected depreciation expense and return on rate base revenue requirements for periods extending beyond the *current* GRC cycle. Better transparency into the full costs that ratepayers will pay over time for capital expenditures may facilitate analysis of the effects of projected capital-related revenue requirement escalation on projected utility rates.

Transparency into program areas with large capital investments such as Transportation Electrification (TE) is important for the CPUC and stakeholders to have a clear understanding of how an IOU’s proposed capital spending will impact revenue requirements beyond the initial years of the program. SCE and SDG&E maintain projected capital cost and capital-related revenue requirements data for certain TE stand-alone programs beyond the year the program terminates.⁵⁰ After program termination, the ongoing capital-related revenue requirements will become part of GRC filings.⁵¹ It is unknown at this time if these ongoing capital-related revenue requirements will be tracked separately in GRC filings.

⁴⁹ The IOUs are in the process of switching over to a four-year cycle from a three-year cycle. PG&E will file its next GRC in 2023, SCE is expected to file a petition requesting the filing of its next GRC in 2025, and SDG&E has filed a petition requesting the filing of its next GRC in 2024.

⁵⁰ SCE and SDG&E provided to Energy Division by data request TE program costs beyond the years the programs terminate out to the year 2030.

⁵¹ TE programs generally have lengths of about five years. Programs initiated as early as 2017 may be terminating, for which the capital-related revenue requirements will roll into the subsequent GRC cycle.

2.4 Net Energy Metering Costs and Benefits

California’s net energy metering (NEM) program started in 1997, prompted by Senate Bill 656 (1995, Alquist). It allows customers who install eligible renewable electrical generation facilities to serve onsite energy needs and receive credits on their electric bills for surplus energy sent to the electric grid. Most customer-sited, grid-connected solar in California is interconnected through NEM tariffs. California’s first NEM program, now colloquially known as “NEM 1.0,” was revised in 2016 via Decision (D).16-01-044⁵² per Assembly Bill (AB) 327 (2013, Perea). Customers on the “NEM successor tariff,” or “NEM 2.0,” pay for their cost to connect to the grid; take service on a “time-of-use” rate plan; and pay “non-bypassable” charges that cannot be offset with surplus energy credits, in order to contribute their fair share toward public purpose programs and other initiatives.

To achieve the mandates of AB 327, the CPUC opened a new proceeding in August 2020 (Rulemaking (R).20-08-020) to revisit the NEM 2.0 tariff.⁵³ The proceeding will be guided by the statutory mandates of AB 327 to ensure the sustainable growth of distributed renewable energy, with benefits approximately equal to costs.

NEM 2.0 Costs and Benefits Study

An independent research firm, Verdant Associates, recently completed an evaluation study of the costs and benefits of NEM 2.0 on behalf of the CPUC.⁵⁴ The CPUC directed this study to gather information in preparation for its planned revisit of the tariff.⁵⁵ The study found that, over time, NEM 2.0 customers usually save more money on their electric bills than they pay for their generation facilities (e.g. a rooftop solar system).

The study also found that the cost to the electric utilities—and their customers—of providing these extra electric bill savings is greater than the energy’s value, i.e. the utility pays more to NEM customers than it would pay elsewhere for the same amount of energy and other electric grid benefits. This is illustrated by the CPUC’s total resource cost (TRC) test, which compares an energy resource’s benefits and costs to both participants and utilities. Using a model representing the NEM 2.0 population, the study found a statewide weighted average TRC ratio of 0.84, meaning the total benefits, \$7.96 billion, are about one-sixth lower than the total costs, \$9.46 billion. A related test, the CPUC’s ratepayer impact measure (RIM) test, calculates effects of an energy resource on customer bills. The model had a NEM 2.0 weighted average RIM ratio of 0.37, with total benefits of \$7.58 billion and total costs of \$20.58 billion. A RIM ratio below 1.0 means that NEM 2.0 increases non-participant bills. Non-NEM customers’ bills rise most, not being offset by onsite

⁵² D.16-01-044 can be accessed at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf>.

⁵³ Documents in R.20-08-020 can be accessed at: https://apps.cpuc.ca.gov/apex/?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R2008020.

⁵⁴ Verdant was previously part of Itron, Inc., the firm that won the competitive solicitation to conduct the NEM 2.0 evaluation study. The study can be accessed at: <https://www.cpuc.ca.gov/General.aspx?id=6442463430>.

⁵⁵ D.18-09-044 can be accessed at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M230/K892/230892616.pdf>.

energy generation. Table 3 shows the TRC and RIM weighted average benefit-cost ratios for the residential customer sector and all sectors.

Table 3: Weighted Average Benefit-Cost Ratios

	Residential		All Sectors (Including Residential)	
	TRC Ratio	RIM Ratio	TRC Ratio	RIM Ratio
PG&E	0.69	0.31	0.80	0.33
SCE	0.80	0.43	0.91	0.49
SDG&E	0.76	0.29	0.84	0.31

The evaluation study found that, as compared to the general California population, NEM customers are disproportionately older, located in high-income areas, likely to own their home, and less likely to live in a disadvantaged community. Consequently, the costs of NEM are disproportionately paid by younger, less wealthy, and more disadvantaged ratepayers, many of whom are renters. To address these concerns, the CPUC is considering modifying the structure of the NEM 2.0 tariff to achieve California’s social and environmental goals for distributed renewable energy while allocating its costs and benefits in a more equitable manner.

NEM Cost Shift Equity Considerations

All residential non-NEM or non-participating customers, including California Alternate Rates for Energy (CARE) customers, shoulder an additional rate burden as a result of the cost shift from NEM customers.⁵⁶

Potential equity concerns related to the NEM cost shift include the following:⁵⁷

- As of November 2020, PG&E had approximately 519,000 residential NEM customers and 1.3 million CARE customers. Of these CARE customers, only about 5 percent are NEM participants, meaning approximately 95 percent of CARE customers did not participate and therefore bear the cost responsibility of compensating NEM customers.
- SCE had, as of December 2020, approximately 361,000 residential NEM customers and 1.5 million CARE customers. Of these CARE customers, only 4 percent participate in NEM, meaning over 1.4 million CARE customers, or about 96 percent, shoulder the additional cost burden from all NEM customers.

⁵⁶ NEM cost shift reflects the cost shift created by residential NEM customers that non-NEM customers (also referred to as “non-participating” customers) may be paying in higher rates. NEM Cost Shift = NEM Customer Bill Savings – Avoided Costs where “Bill Savings” is the yearly dollar amount that NEM customer avoid paying because of their self-generation and netting (compensation) and “Avoided Costs” are fixed and variable costs of service that the utility should avoid incurring as a result of distributed generation.

⁵⁷ This information was gleaned from IOU data responses submitted to Energy Division.

- As of November 2020, SDG&E had approximately 199,000 residential NEM customers and 320,000 CARE customers. Of these CARE customers, only 8 percent are NEM participants. CARE customers are currently seeing bills that are 13 percent higher as a result of the NEM cost shift.

2.5 Historical Distribution Costs

Distribution costs include O&M and capital-related costs associated with distribution infrastructure. This reflects the costs to distribute power to customers and includes power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety. In addition, the CPUC has authorized the IOUs to recover funding related to specific public policy objectives such as transportation electrification and demand response through the distribution rate component. Here we focus on distribution costs associated with transportation electrification and wildfire mitigation.

Historical Transportation Electrification Costs

Legislative Background

The CPUC is responding to several legislative mandates and gubernatorial directives to support and accelerate widespread transportation electrification (TE).⁵⁸ SB 350 directed the CPUC to require the investor-owned utilities (IOUs) to submit applications for programs that leverage ratepayer funding to support electric vehicle (EV) adoption.⁵⁹ To date, the CPUC has authorized the IOUs to implement many TE programs to help meet California's zero-emission vehicle (ZEV) targets of five million ZEVs on the road by 2030 and 250,000 installed publicly available EV charging stations and 200 publicly available hydrogen fueling stations in the state by 2025.⁶⁰

In September 2020, Governor Newsom pushed these state goals further by issuing Executive Order N-79-20 to require all in-state sales of new passenger vehicles be zero-emission by 2035. The Executive Order also set a further goal that 100 percent of medium- and heavy-duty vehicles in the state be zero-emission by 2045 for all operations where feasible and by 2035 for drayage trucks. Further, it sets a state goal to transition to 100 percent zero-emission off-road vehicles and equipment by 2035 where feasible.

Additionally, AB 841 (Ting, 2020) was signed into law in September 2020. The bill directs the establishment of new electric rules or tariffs that authorize each IOU to design and deploy all utility-side electrical distribution infrastructure for customers installing separately metered EV charging. This changes the CPUC practice of authorizing utility-side, electrical distribution infrastructure needed to charge EVs⁶¹ on a case-by-

⁵⁸ 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.

⁵⁹ Such as multi-unit dwellings, workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.

⁶⁰ Executive Order (E.O.) B-48-18.

⁶¹ Section 740.19(b) defines "electrical distribution infrastructure" as including poles, vaults, service, drops, transformers, mounting pads, trenching, conduit, wire, cable, meters, other equipment as necessary, and associated engineering and civil construction work.

case basis through individual program applications, to authorization of that infrastructure and associated design, engineering, and construction costs on an ongoing basis in an IOU's general rate case (GRC). The bill also makes permanent the exemption to CPUC Electric Rules 15 and 16, which allows service facility upgrade costs resulting from residential EV charging to be treated as a common cost paid for by all ratepayers.

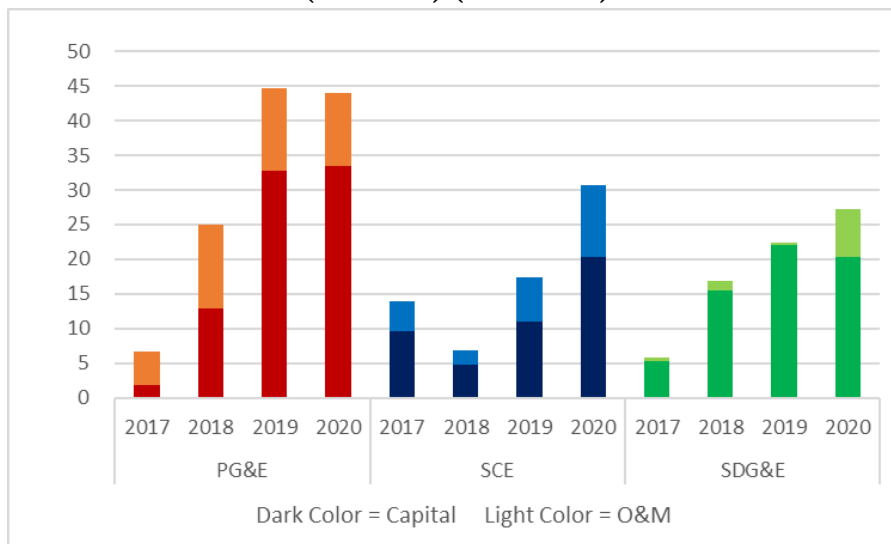
Costs in Rates

As of fourth quarter 2020, the CPUC has authorized the IOUs to spend approximately \$1.6 billion on EV charging infrastructure to support the state's TE goals and is considering another application from SDG&E for approximately \$44 million in TE funding.⁶²

- Out of the authorized IOU funding to date, \$238 million has been spent.
- Another \$1.29 billion is still available for TE investment.

Figure 19 shows each IOU's transportation electrification program spending by O&M and capital cost classification and by the year implemented in rates.

Figure 19: PGE, SCE, and SDG&E Transportation Electrification Program Costs in Rates (\$ million) (2017 -2020)



⁶² See "Transportation Electrification Investments" on CPUC website: <https://www.cpuc.ca.gov/zev/>.

Table 4 shows the rate attributable to transportation electrification costs embedded in the bundled average residential rate for the period 2017 to 2020.⁶³

Table 4: Transportation Electrification Rate Embedded in Bundled Residential Average Rate (nominal \$/kWh) (2017 – 2020)

	Transportation Electrification Rate Embedded in Bundled Residential Average Rate (nominal \$/kWh)				Bundled Residential Average Rate (nominal \$/kWh)			
	2017	2018	2019	2020	2017	2018	2019	2020
PG&E	0.00004	0.00027	0.00049	0.00033	0.204	0.205	0.220	0.230
SCE	0.00010	0.00005	0.00019	0.00025	0.177	0.181	0.183	0.209
SDG&E	0.00017	0.00043	0.00057	0.00139	0.249	0.276	0.263	0.271

With California’s aggressive goals for transportation electrification over the next decade, significant upgrades to the distribution grid may be necessary to accommodate charging demand. While there is an ongoing policy discussion regarding the extent of ratepayer responsibility for TE costs, there is the potential for these costs to drive rate increases.

Historical Wildfire-Related Costs

Wildfire-related costs fall into several categories. First, the IOUs incur costs to implement wildfire mitigation activities. The costs associated with wildfire mitigation activities are recovered by the IOUs in General Rate Cases or through separate applications.

The CPUC also allows the IOUs to recover certain wildfire-related costs for liabilities, including insurance premiums. These costs are tracked through a mechanism called a Wildfire Expense Memorandum Account (WEMA). WEMAs track wildfire related liability costs, and no other category. WEMAs are designed to allow the utility the ability to track its costs incurred for claims made against the company as a result of property losses, in addition to other incremental liability costs including (but not limited to) higher-than-forecasted insurance premiums and legal fees.

In 2019, the Legislature also established a Wildfire Fund for excess liabilities. This is discussed in more detail below in the section on legislative background.

Legislative Background

⁶³ Year-end effective rates. Transportation Electrification rates expanded to five decimal places as the three decimal place convention in this paper produces 0.000 and 0.001 rates. To get an estimate of the portion of the monthly bill to which the transportation electrification rate corresponds, multiply the rate by 500 kWh, the monthly usage data that is used in legal bill inserts for PG&E’s 2020 GRC Phase II, SCE’s 2021 GRC Phase II, and SDG&E’s 2019 GRC Phase II applications.

SB 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMP), which describe the level of wildfire risk in their service territories and how they intend to address those risks.⁶⁴ The WMPs cover a three-year period with new comprehensive plans to be filed at least once every three years and annual updates to the plans in between.

AB 1054 Wildfire Fund and Securitization

AB 1054 created a \$21 billion Wildfire Fund to be funded equally by ratepayers and utilities. Utility shareholders will contribute approximately \$10.5 billion to the Wildfire Fund through annual payments until 2030. Ratepayer funding amounts to an additional \$10.5 billion which will be funded through a new non-bypassable charge (NBC). D.20-09-023 adopted a charge of \$0.0058 per kWh from October 1, 2020-December 31, 2020 to support the Wildfire Fund and D.20-12-024 adopted the same charge for calendar year 2021. This amounts to approximately \$3 per month for an average residential customer using 500 kWh per month.⁶⁵

The Wildfire Fund is designed to act as an insurance fund for the utilities and can be used to pay costs resulting from utility caused wildfires provided that certain conditions are met by the utility. While the fund represents an ongoing surcharge to rate payers it could reduce costs to ratepayer over time by creating more certainty for utility investors and thus reducing utility operating and borrowing costs.

AB 1054 Securitization and Rate Payer Savings

In addition, AB 1054 contains two separate benefits for ratepayers related to Wildfire Mitigation Plan (WMP) capital spending. AB 1054 requires the first \$5 billion of WMP capital spending be excluded from earning a Return on Equity (ROE). This reduces rates directly by eliminating the shareholder profit portion of the return on rate base on the \$5 billion WMP capital spending. Of the \$5 billion in capital expenditures total, PG&E's share is \$3.21 billion, SCE's share is \$1.575 billion, and SDG&E's share is \$215 million.

AB 1054 also allows for this \$5 billion capital spending to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings. This securitization benefits ratepayers by allowing the utility to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures. On July 8, 2020, SCE filed A.20-07-008 with the CPUC, becoming the first utility to file for this securitization provision of AB 1054. In D.20-11-007, the CPUC granted forming the Financing Order allowing the securitization, subject to certain conditions.

Costs in Rates

SB 901 and AB 1054 permitted the IOUs to open accounts in 2019 to track spending to implement their WMPs. The IOUs are allowed to seek recovery of this spending in their General Rate Cases or through a

⁶⁴ See each IOU's WMP at <https://www.cpuc.ca.gov/2019wmp/>.

⁶⁵ CARE and Medical Baseline customers are exempt from paying the non-bypassable charge.

separate application, after the conclusion of the time period covered by the plan. Therefore, there is lag between when spending takes place and when it is reflected in rates.

Table 5 shows spending related to the WMPs that is reflected in 2019 and 2020 rates is minimal compared to increases expected in future years for PG&E and SCE. SDG&E’s spending is higher relative to their revenue requirement as a result of programs adopted in response to fires in their service territory in 2007.⁶⁶

Table 5: Wildfire Mitigation Plan Costs in Rates (2019 - 2020)

	2019		2020	
	O&M Costs in Rates	Capital Costs in Rates	O&M Costs in Rates	Capital Costs in Rates
PG&E	-	\$13.7 million	\$20.3 million	\$15.8 million
SCE	\$33.9 million	\$3.0 million	\$173.1 million	\$82.4 million
SDG&E	\$25.8 million	-	\$28.3 million	-

After destructive fires in SDG&E’s service territory in 2007, the CPUC approved SDG&E cost recovery applications for a total of about \$1.7 billion dollars over the period 2007 – 2018 for grid hardening, situational awareness, and vegetation management to better address the risk of wildfires. Figure 20 and Figure 21 show O&M and capital costs incurred⁶⁷ for wildfire prevention over the period 2007 – 2018 relative to all other non-wildfire costs, with wildfire prevention distribution spending directly representing over half of the total wildfire prevention costs.⁶⁸

⁶⁶ FERC-related costs are not included in SDG&E’s filed WMPs.

⁶⁷ Costs may be implemented in rates in a different year than year incurred.

⁶⁸ Other wildfire prevention costs represented include FERC-jurisdictional and mixed CPUC GRC and FERC Common costs.

Figure 20: SDG&E Wildfire Prevention O&M Costs Relative to All Other O&M Costs (Non-Wildfire), (\$ million)

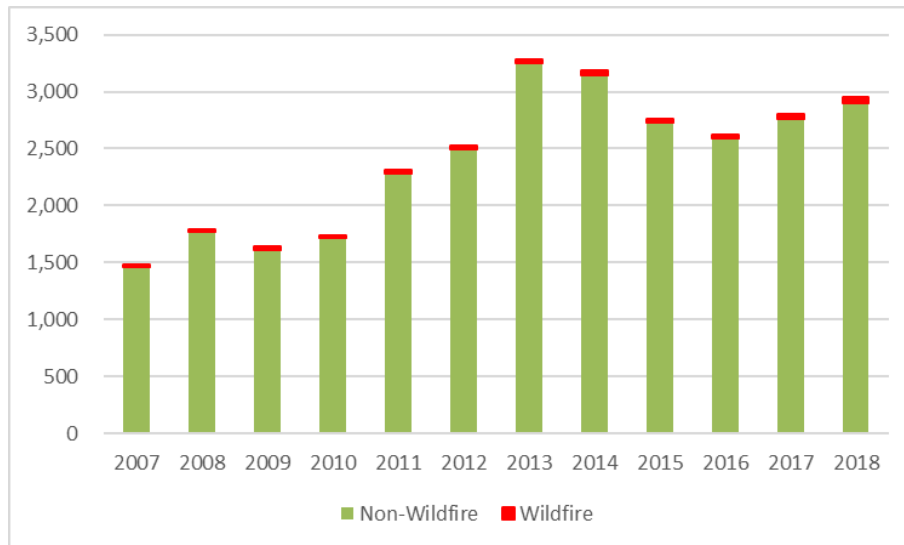


Figure 21: SDG&E Wildfire Prevention Capital Costs Relative to All Other Capital Costs (Non-Wildfire), (\$ million)

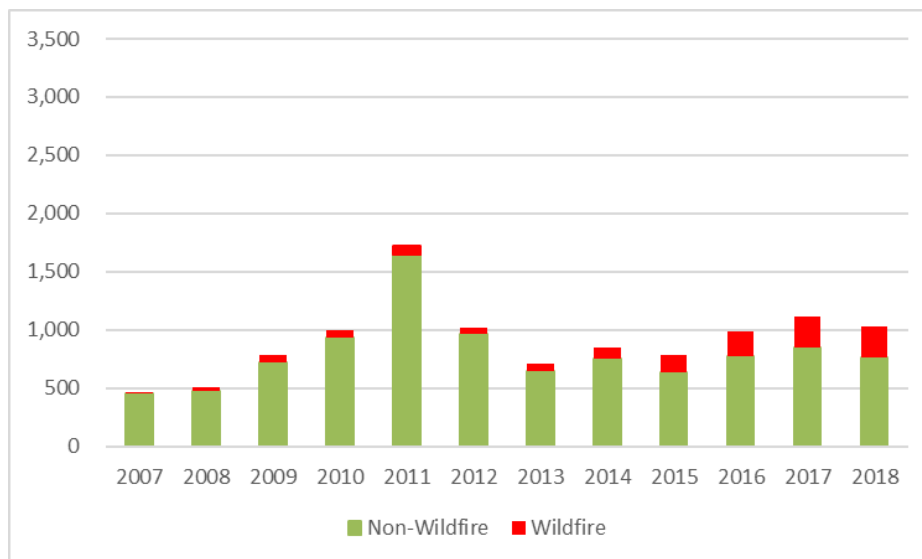


Figure 21 shows SDG&E’s wildfire prevention capital expenditures increasing over time, particularly after 2013. Table 6 shows this wildfire prevention capital spend by SDG&E-designated cost categories for the years 2016 to 2018.

Table 6: SDG&E Wildfire Prevention Capital Expenditures by Cost Category (\$ million) (2016 – 2018)

Cost Category (\$ million)	2016	2017	2018
Wood-to-Steel (WTS) Pole Replacement Program	46.5	42.3	45.5
Cleveland National Forest (CNF) Projects	84.8	125.8	120.5
Fire Risk Mitigation (FiRM) Program	86.2	89.6	94.3
IntelliRupters	0.2	0.3	0.2
Emergency Communications/Trailers	0.1	0.4	0
Weather Modeling & Analytics	1.4	3.4	0.4
Pole Risk Mitigation Engineering (PRiME) Program	0	0	5
Total	219.2	261.8	265.9

The spending trends in Figure 20 and Figure 21 reflect SDG&E’s increased focus in the last decade on hardening its electric system in high fire threat areas. These programs have expanded in recent years in response to the catastrophic wildfires of 2017-19. SDG&E wildfire mitigation costs since its destructive 2007 fires have not declined; in fact, they have continued to increase. This trend of wildfire spending by SDG&E may be informative of future spending by PG&E and SCE as these utilities ramp up their wildfire mitigation programs and harden their systems.

2.6 Historical Transmission Costs

Transmission revenue requirements (TRR) have been on the rise in recent years, driven largely by Capital Additions, Operations & Maintenance (O&M) costs, and Administrative & General (A&G) expenses. Collectively, the three big IOUs’ annual spending has increased by approximately 60 percent on capital additions, 80 percent on O&M, and nearly 30 percent on A&G. The resulting Transmission Access Charge (TAC) that is paid by all ratepayers has been increasing while the total annual gross load has been declining in the California Independent System Operator (CAISO) control area.

Background

Transmission costs are set by the Federal Energy Regulatory Commission (FERC) and not by the CPUC, and Transmission Owners (TO) in the CAISO control area file at FERC to recover costs through transmission rates. At FERC, the CPUC represents California ratepayers as an advocate for just and reasonable rates. In the Transmission Owner rate cases, FERC approves revenue requirements recovered from both wholesale and retail transmission customers of larger IOUs such as PG&E, SCE, and SDG&E, as well as smaller merchant TOs. As explained in the CPUC’s 2020 *California Electric and Gas Utility Cost*

Report (AB 67 Report), the proportion of a retail customer’s cost per kilowatt hour attributed to transmission in 2019 was 16.6 percent for PG&E, 9.1 percent for SCE, and 15.1 percent for SDG&E.⁶⁹

Transmission Revenue Requirements Are Increasing Rapidly

In recent years, the sum of the three IOUs’ transmission revenue requirements (TRR) has increased 38.1 percent, from \$3.14 billion in 2016 to \$4.34 billion in 2021 as forecasted in the three IOUs’ rate filings at FERC on December 1, 2020. While this is a total increase of 38.1 percent, PG&E’s TRR has increased over 66 percent during that time and SDG&E’s by nearly 45 percent. After a dip during this period, SCE’s TRR is at the same level it was in 2016. Further, the TRR and resulting electric transmission rates are driven by Operations & Maintenance costs and Administrative & General expenses. While the sum of operations and maintenance (O&M) costs for the three IOUs was \$375.5 million in 2016, O&M costs have increased to a forecasted \$674.6 million in 2021 – a nearly 80 percent increase. A&G also increase by almost 30 percent across the three IOUs. Table 7 through Table 10 show this data.

Table 7 shows the differences in transmission revenue requirements between 2016 and the 2021 forecast in total and for the individual utilities, reflecting increasing revenue requirements with the exception of SCE.

Table 7: Transmission Revenue Requirements in Settled TO Rate Cases at FERC

Utility	2016	2021	Percentage Change
SDG&E	\$ 716 million	\$ 1.036 billion	44.7%
SCE	\$ 1.092 billion	\$ 1.087 billion	-0.5%
PG&E	\$ 1.331 billion	\$ 2.214 billion	66.3%
Total	\$ 3.139 billion	\$ 4.336 billion	38.1%

Each IOUs’ rate base, meaning the transmission capital investment on which the utility receives an approved rate of return, has significantly increased over the same period, as shown in Table 8.

Table 8: Transmission Rate Base

Utility	2016	2021	Percentage Change
SDG&E	\$ 2.896 billion	\$ 4.342 billion	49.9%
SCE	\$ 5.171 billion	\$ 6.428 billion	24.3%
PG&E	\$ 5.846 billion	\$ 8.476 billion	45.0%
Total	\$ 13.914 billion	\$ 19.246 billion	38.3%

Table 9 shows the overall increase of nearly 80 percent in annual O&M costs since 2016, with PG&E’s rate base increasing a staggering 118 percent. O&M costs are also impacted by the substantial increases in rate base, but the primary driver of these costs is wildfire mitigation work, including enhanced inspections and vegetation management efforts.

⁶⁹ CPUC’s 2020 *California Electric and Gas Utility Cost Report: AB 67 Report to the Governor and Legislature, p.10 (April 2020).*

Table 9: Operations & Maintenance Expenses

Utility	2016	2021	Percentage Change
SDG&E	\$ 62.5 million	\$ 85.6 million	37.0%
SCE	\$ 93.5 million	\$ 110.9 million	18.6%
PG&E	\$ 219.5 million	\$ 478.1 million	117.8%
Total	\$ 375.5 million	\$ 674.6 million	79.7%

The most variable transmission cost category is Administrative & General (A&G) expenses, which have fluctuated substantially from year-to-year. As these expenses have been influenced by injuries and damages related to wildfires for SCE and PG&E in recent years, SDG&E's A&G costs have declined as more time has passed since it experienced major wildfire impacts, as shown in Table 10.

Table 10: Administrative & General Expenses

Utility	2016	2021	Percentage Change
SDG&E	\$ 79.9 million	\$ 70.0 million	-12.4%
SCE	\$ 49.7 million	\$ 81.8 million	64.5%
PG&E	\$ 73.6 million	\$ 111.1 million	50.9%
Total	\$ 203.2 million	\$ 262.8 million	29.3%

Growth in Transmission Capital Additions

As described above, FERC reviews and approves transmission owner rate cases, which allow recovery of costs of service for the network transmission system under the CAISO's operative control. A critical driver of these overall transmission increases has been a continual rise in annual capital investment by the utilities, also referred to as "capital additions," from \$2.14 billion in 2016 to a forecasted capital addition of \$2.59 billion in 2021, an approximately 21 percent increase.

The rate of return (ROR) on capital additions allows utility shareholders to earn profits for shareholders' benefit. Utilities have an incentive to seek FERC approval for the highest possible ROR. The more capital additions that go into operation, the more profit the IOUs can attain. Conservative assumptions indicate that every dollar put into transmission rate base costs ratepayers in excess of \$3.50 over the life of a transmission asset. For example, the \$2.75 billion in capital additions for the three IOUs in 2020 alone can be expected to cost ratepayers at least \$9.7 billion over the lives of the assets, using a conservative asset life estimate of 36 years.⁷⁰

Utilities do not start collecting revenue for capital investments in transmission projects until the projects are completed and put into service. This means that ratepayers can see a large increase in the transmission portion of their bill when expensive projects are complete. Table 11 shows the in-service date of the largest transmission projects over the past 10 years. For two of the three projects in Table 11, the final total costs

⁷⁰ Transmission asset lives typically range between 30 to 50 years, and 36 years is chosen as a conservative mid-range estimate.

that were approved by FERC exceeded the original total cost estimates provided to the CAISO and the CPUC as part of the planning process.

Table 11: Large CAISO-approved Transmission Projects

Project	Original Est. Cost	Cost	In Service Date	IOU Territory
Sunrise Powerlink	\$1.9 billion	\$1.9 billion	2012	SDG&E
Devers-Colorado River	\$545 million	\$775 million	2013	SCE
Tehachapi Renewable Transmission Project	\$1.7 billion	\$3.062 billion	2016	SCE

Another factor that can accentuate the impacts of capital projects on ratepayers was the issuance of FERC Order No. 679 in 2006,⁷¹ which provided incentives pursuant to Section 219 of the Federal Power Act⁷² to promote necessary transmission development in the wake of the August 2003 Northeast-Midwest blackout. These incentives enable a utility to collect certain costs before it normally would, or ensure the ability to collect the costs on a project that needs to be abandoned through no fault of the utility. In addition, incentives boost the utility’s ROE, either across the entire rate base or for specific projects. Over the last decade, these incentives have cost California ratepayers hundreds of millions of dollars.

An example of a utility ROE incentive is the adder FERC has awarded to transmission owners for participation in the CAISO. This incentive was meant to encourage utilities to join Independent System Operators and Regional Transmission Organizations. Despite the fact that the California IOUs’ participation in CAISO is required under California law, FERC still grants a 50-basis point (0.5 percent) ROE adder to each IOU as an “incentive” for its membership in the CAISO. The CPUC is litigating the reasonableness of awarding an incentive to the IOUs for remaining a member of the CAISO. Currently, this incentive costs California ratepayers over \$70 million annually.

An example of a project-specific ROE incentive is the 125-basis point (1.25 percent) adder granted to SCE in 2007 for the Tehachapi Renewable Transmission Project. The FERC declaratory order granted this incentive for the entire \$1.7 billion project.⁷³ However, at this time, the cost of the project has nearly doubled, with over \$3.06 billion placed into rate base.⁷⁴ It appears that SCE will seek the incentive ROE on the total project cost of \$3.06 billion.

Increase in Utility Self-Approved Projects

⁷¹ *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006)

⁷² 16 U.S. Code § 824s - Transmission infrastructure investment

⁷³ Order Granting Petition for Declaratory Order, EL07-62, 121 FERC ¶ 61,168, P135 (November 16, 2007).

⁷⁴ Southern California Edison Company’s Formula Transmission Rate Annual Update Filing in Docket No. ER19-1553 (TO2021), Attachment 2 to Appendix IX: Formula Rate Spreadsheet, 14-IncentivePlant, line 66 (November 20, 2020).

Projects that expand the capacity of the transmission grid are included in CAISO’s annual Transmission Planning Process (TPP), pursuant to requirements of FERC Order No. 890 (“Order 890”), which requires transparent transmission planning. However, a majority of the California IOUs’ spending on capital additions is not related to grid capacity expansion and therefore receives no review by the CAISO through the TPP. FERC has determined that Order 890 does not apply to projects that do not expand the capacity of the transmission grid. These projects that are outside of the scope of the TPP are referred to as “self-approved.” A TO rate case at FERC includes no review of specific utility self-approved projects. The end result is that there is no state or federal review on either the need or costs for these projects.

In data reported by the IOUs to the CPUC in July 2020, capital additions between 2016 and 2019 for all three IOUs totaled over \$7.5 billion. Approximately \$4.5 billion (60 percent) of these capital additions were utility self-approved, while \$3 billion were CAISO-approved. The annual average for all capital additions for 2016 to 2019 was \$1.875 billion. In comparison, in 2010, the capital additions for the IOUs totaled less than \$950 million, with the share of self-approved projects in 2010 at 50.6 percent and CAISO-approved projects was 49.4 percent. The annual capital additions projected for just 2020 and 2021 total \$5.3 billion, with approximately 60 percent being self-approved projects across all three IOUs, with PG&E exceeding 80 percent self-approved.

As the previous table shows, the largest CAISO-approved projects occurred in SDG&E’s and SCE’s territories. Table 12 shows the proportion of CAISO-approved and utility self-approved projects between 2010 and 2019. While over 80 percent of SCE’s and SDG&E’s project costs during that time were CAISO-approved, primarily because of the large projects in Table 11 only 31 percent of PG&E’s capital additions were CAISO approved. PG&E’s overall capital project costs far exceed those of either SCE or SDG&E and a large majority of those costs were self-approved.

Table 12: CAISO-approved and Utility Self-approved Projects 2010-2019 (\$000)

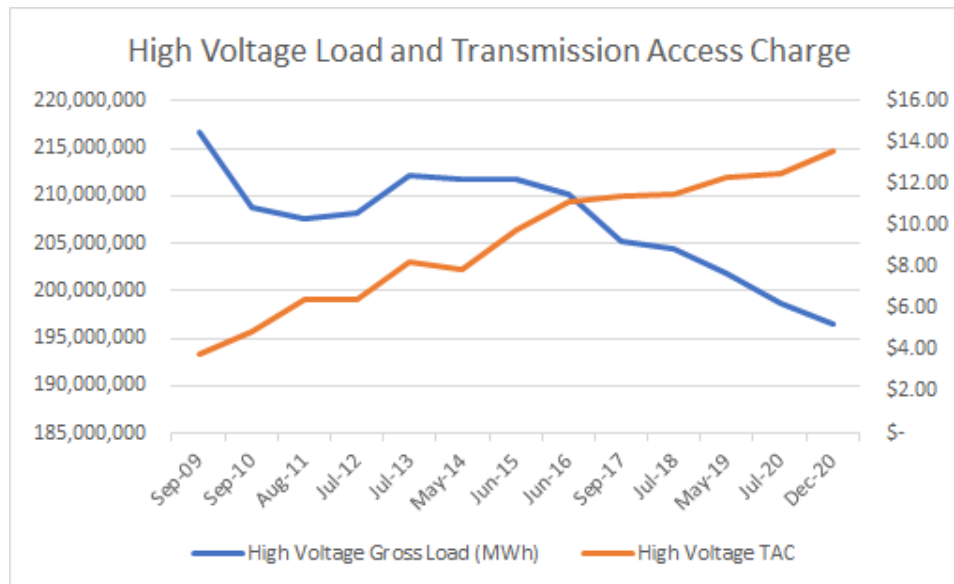
Utility	Self-approved Projects	CAISO-approved Projects	Total Capital Additions	Percentage Self-approved	Percentage CAISO-approved
SDG&E	\$ 0.81 million	\$ 3.99 million	\$ 4.80 million	16.9%	83.1%
SCE	\$ 1.18 million	\$ 5.08 million	\$ 6.26 million	18.9%	81.1%
PG&E	\$ 6.16 million	\$ 2.77 million	\$ 8.93 million	69.0%	31.0%
Total	\$ 8.15 million	\$11.84 million	\$19.99 million	40.8%	59.2%

Declining Loads and Increasing Rates

For more than a decade, the total annual gross load, which is a measure of all energy delivered for the supply of end-use customer loads, has been declining in the CAISO control area. However, over that same period, CAISO’s High Voltage Transmission Access Charge (TAC), which is a primary component of transmission charges on customers’ bills, has increased substantially. In 2009, the annual load in the CAISO

was 216.7 million megawatt hours (MWh).⁷⁵ Figure 22 shows as of December 2, 2020, the load forecast for 2021 was down to 196.5 million MWh, a decline of 9.3 percent. Meanwhile, as of December 2020 the forecast for the 2021 high voltage TAC was \$13.60 per MWh, a 255 percent increase from \$3.83 per MWh in 2009.⁷⁶

Figure 22: High Voltage Load and Transmission Access Charge



2.7 Legislative Policy Program Costs

Clean energy and other legislative mandates for the 5-year period 2016 – 2020 are shown in Table 13, listed from the highest to lowest total cost (or cost reduction) in total electric revenue requirement equivalent. Programs classified as primarily related to clean energy are highlighted in blue-green, with those that are primarily not related to clean energy highlighted in light-purple.⁷⁷ This table shows program costs but does not calculate possible savings to the utility ratepayers; the CPUC details these costs and benefits in other reports. For example, while the Renewable Portfolio Standard (RPS) creates added costs there is also a savings from avoided procurement of other generation, with savings increasing over time as renewables become less and less expensive.⁷⁸

⁷⁵ High Voltage Load and TAC data for 2009 through July 2020 derived from: California ISO September 01, 2009 TAC Rates, California ISO September 01, 2010 TAC Rates, California ISO August 01, 2011 TAC Rates, California ISO July 03, 2012 TAC Rates, California ISO July 01, 2013 TAC Rates, California ISO May 01, 2014 TAC Rates, California ISO June 01, 2015 TAC Rates, California ISO June 01, 2016 TAC Rates, California ISO September 15, 2017 TAC Rates, California ISO July 01, 2018 TAC Rates, California ISO May 01, 2019 TAC Rates, and California ISO July 01, 2020 TAC Rates.

⁷⁶ Pacific Gas and Electric Company Transmission Owner Tariff Transmission Access Charge Balancing Account Filing, Exhibit PGE-003, p. 2 of 12, FERC Docket No. ER21-657 (December 15, 2020).

⁷⁷ The list of legislatively mandated programs does not capture programs that result in a cost shift or cross-subsidy between various customers groups. This includes, but is not limited to, programs such as Net Energy Metering (AB 920), California Alternate Rates for Energy (AB 3), the FERA Program (Federal Emergency Relief Act of 1993), and the Medical Baseline Program (PUC Code 739).

⁷⁸ See *Costs and Cost Savings for the RPS Program* (Padilla Report) at: <https://www.cpuc.ca.gov/General.aspx?id=6442463728>.

Table 13: Programs Mandated by California Statute, Electric Revenue Requirement in Rates, Five Year Total (2016 – 2020)

2016 – 2020 Five-Year Total (\$ million)					
Legislation	Program Name	PG&E	SCE	SDG&E	Total
SB 1078, SB 350, SB 100	Renewable Portfolio Standard ⁷⁹	\$10,710	\$11,039	\$3,413	\$25,162
AB 1X	Department of Water Resources Bond	\$2,028	\$2,023	\$450	\$4,501
AB 32	Greenhouse Gas Revenue Return	\$(1,896)	\$(1,800)	\$(403)	\$(4,099)
SB 350, AB 1330, AB 802, AB 32, AB 1890	Energy Efficiency	\$1,467	\$1,205	\$497	\$3,169
AB 32	Greenhouse Gas Cost	\$386	\$1,530	\$158	2,074
Public Utilities Code § 2790, § 382; AB 327, AB 2857, SB 580, AB 2140	Energy Savings Assistance Program and California Alternate Rates for Energy Program Administrative Expense	\$729	\$364	\$609	\$1,702
Public Utilities Code § 399.8; AB 1890	Electric Program Investment Charge	\$463	\$366	\$78	\$907
SB 1414, AB 793	Demand Response ⁸⁰	\$212	\$306	\$81	\$599
AB 970, SB 700, AB 1144	Self-Generation Incentive Program	\$240	\$227	\$72	\$539
AB 1X	Total Rate Adjustment Component	\$0	\$0	\$533	\$533
Public Utilities Code § 431-432	CPUC Fee	\$187	\$195	\$46	\$428
AB 693	Solar on Multifamily Affordable Housing	\$146	\$161	\$32	\$339
SB 1, AB 217, AB 2723	California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	\$40	\$121	\$11	\$172

⁷⁹ RPS revenue requirements do not distinguish the above-market portion.

⁸⁰ Demand Response includes DR Auction Mechanism and IDSM, as applicable.

2016 – 2020 Five-Year Total (\$ million)					
Legislation	Program Name	PG&E	SCE	SDG&E	Total
SB 859	Tree Mortality Non-Bypassable Charge	\$100	\$50	\$21	\$171
AB X1 6	Hazardous Substance Memorandum Account	\$147	\$14	\$2	\$163
Public Utilities Code § 2791-2799	Mobile Home Park Program	\$55	\$72	\$15	\$142
SB 350, AB 1082, AB 1083, AB 628	Transportation Electrification Programs ⁸¹	\$76	\$33	\$22	\$131
SB 1, AB X1 15	New Solar Homes Partnership Program	\$57	\$46	\$10	\$113
Other	Other ⁸²	\$156	\$140	\$13	\$309
Five-Year Total⁸³		\$15,303	\$16,092	\$5,660	37,055
One-Year Average Total⁸⁴		\$3,061	\$3,218	\$1,132	\$7,411

⁸¹ Transportation Electrification includes pilots, as applicable.

⁸² Other includes: AB 793 Statewide Marketing Program; AB 32, SB 17, Smart Grid; SB 43 Green Tariff Shared Renewables; SB 96 California Energy Systems for 21st Century; AB 2514 Aliso Canyon Energy Storage; AB 2672 San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering; AB 327 Disadvantaged Communities - Single-Family Affordable Solar Homes, Green-Tariff, Community Solar Green Tariff; SB 987, SB 1135 Family Electric Rate Assistance (administrative expense); AB 1070 Net Energy Metering (solar system contracts and disclosures); SB 901 Officer Compensation.

⁸³ Not all programs have five years of data; for example, programs may have started within the five-year period for which less than five years data will be shown.

⁸⁴ *Ibid.*

III. MODELING ASSUMPTIONS AND FRAMEWORKS FOR EVALUATING FORECASTED UTILITY COSTS

3.1 Section Summary

Public Utilities Code Section 913.1(a) requires the CPUC's to make recommendations for actions that can be undertaken during the succeeding 12 months⁸⁵ to limit utility cost and rate increases, consistent with the state's energy and environmental goals, including goals for reducing emissions of greenhouse gases. For the 2021 SB 695 Report contained within this white paper, the CPUC is presenting a 10-year bundled⁸⁶ residential rates forecast as a backdrop for discussion related to the white paper.

This section describes the process by which the 10-year forecast was developed, starting with a description of the cost and rate tracking tools used to project IOU rates in the near-term (1 to 3 years) followed by a summary of the methodology used to extend the forecast out to 2030. The baseline forecast shows steady growth in bundled rates (nominal \$/kWh) between 2020 and 2030 for the three IOUs:

- PG&E: \$0.240 to \$0.329, or about an annual average increase of 3.7 percent
- SCE: \$0.217 to \$0.293, or about an annual average increase of 3.5 percent
- SDG&E: \$0.302 to \$0.443, or about an annual average increase of 4.7 percent

By 2030, bundled residential rates are forecasted to be approximately 12 percent, 10 percent, and 20 percent higher, respectively, than they would have been if 2020 actual rates for each IOU had grown at the rate of inflation.⁸⁷

This section also describes how costs were projected for two specific components of the rates forecast: wildfire management and transportation electrification. Component contribution to the forecasted bundled residential rates is also presented. These costs are of particular interest because there is a great deal of uncertainty around their growth in the coming decade. The portion of the baseline forecasted bundled residential rates that corresponds to wildfire management and transportation electrification rates in 2021 and 2030 is shown in Table 14.

⁸⁵ The succeeding 12 months refers to the 12-month period after the report is submitted by May 1 of each year.

⁸⁶ Bundled IOU customers receive all services from the IOU: generation, transmission, and distribution services.

⁸⁷ 2020 rates are actual rates in effect at yearend 2020; if 2020 rates were to increase at the rate of inflation (approximately 1.9% per year), rates in 2030 would be: PG&E 0.294; SCE 0.266; SDG&E 0.370. Inflation is approximately 1.9% per year.

Table 14: Wildfire Management and Transportation Electrification Embedded Rates as a Portion of Forecasted Bundled Residential Rate (nominal \$/month)

	2021					2030				
	Embedded Wildfire Rate (\$/kWh)	Embedded TE Rate (\$/kWh)	Forecasted Bundled Residential Rate (\$/kWh)	Wildfire Portion %	TE Portion %	Embedded Wildfire Rate (\$/kWh)	Embedded TE Rate (\$/kWh)	Forecasted Bundled Residential Rate (\$/kWh)	Wildfire Portion %	TE Portion %
PG&E	0.016	0.001	0.266	6.0%	0.4%	0.028	0.001	0.329	8.5%	0.3%
SCE	0.024	<0.001	0.272	8.8%	<0.4%	0.025	0.003	0.293	8.5%	1.0%
SDG&E	0.019	0.002	0.300	6.3%	0.7%	0.029	0.006	0.443	6.5%	1.4%

Table 15 shows the wildfire management and transportation electrification portion of monthly forecasted bundled residential customer bills in 2021 and 2030.⁸⁸

Table 15: Wildfire Management and Transportation Electrification Portion of Monthly Forecasted Bill, Bundled Residential Customers (nominal \$/month)

	2021					2030				
	Wildfire Portion (\$/month)	TE Portion (\$/month)	Total Bill (\$/month)	Wildfire Portion %	TE Portion %	Wildfire Portion (\$/month)	TE Portion (\$/month)	Total Bill (\$/month)	Wildfire Portion %	TE Portion %
PG&E	8.00	0.50	133.00	6.0%	0.4%	14.00	0.50	164.50	8.5%	0.3%
SCE	12.00	<0.50	136.00	8.8%	<0.4%	12.50	1.50	162.00	7.7%	0.9%
SDG&E	9.50	1.00	150.00	6.3%	0.7%	14.50	3.00	221.50	6.5%	1.4%

The results of the rate forecasting exercise were then used as an input to a consultant-developed Residential Energy Cost Calculator (RECC) tool, along with projections of natural gas and gasoline prices. The tool was used to estimate changes in total energy bills for an example household with greater-than-average energy usage⁸⁹ to demonstrate the cost implications for Californians who are most sensitive to energy price shocks.

This analysis shows that energy bills for this greater-than-average energy usage household are forecasted to rise **at an annual rate of 4.5 percent**, implying that households' energy burdens will increase if household incomes track the assumed inflation rate of 1.9 percent.

This analysis implies that, in order for Californians to avoid forecasted increases in energy bills, large up-front investments may be needed. From an equity perspective, this will pose a significant challenge in an environment where affordability disparities are already evident. A recent analysis using CPUC-developed

⁸⁸ Bills are for illustrative purposes only.

⁸⁹ Greater than average usage in the consultant-developed tool is approximately 680 kWh/month.

metrics indicates that there are significant disparities across the state in terms of low-income households' ability to pay for utility services. The analysis found that there are specific geographic areas within the state where affordability concerns are most acute, including Oakland, Stockton, Fresno, Modesto, Tulare County, Bakersfield, San Bernardino, and many parts of Los Angeles.

These observed disparities may be exacerbated in the coming years as the impacts of the COVID-19 pandemic and accompanying economic recession unfold. Preliminary economic data indicates that prior disparities have likely worsened over the past year. Furthermore, experience from the last recession of 2008 indicates that disadvantaged households take a longer time to recover from economic downturns, and there is no reason to believe this recession will be any different.

3.2 Cost and Rate Tracking Tools (CRT)

Background

In an ongoing proceeding to better assess affordability of utility bills in California, the CPUC ordered PG&E, SCE, and SDG&E to each submit a quarterly cost and rate tracking tool (CRT) to the CPUC's Energy Division for evaluating the inputs of the affordability metrics developed as part of the OIR and for other ongoing support of the CPUC's work.⁹⁰ In addition to producing rates for the affordability metrics, each IOU's CRT is used to produce a short- to medium term comprehensive⁹¹ rate forecast to show overall rate trends as requested by CPUC Commissioners or other parties. This tool will also be used to provide Commissioners and the public a clear understanding of the bill impacts of individual decisions made by the CPUC. The CRT can produce estimated bills for bundled residential customers at the IOU service territory or climate zone level.

The CRT models comprehensive forecasted revenue requirement⁹² and forecasted sales information, as provided by the large electric IOUs,⁹³ to produce rates. While the CRT will help inform CPUC decisions, the tool may still have limitations based on the completeness and classification of data provided by the utilities. For example, certain wildfire mitigation plan cost recovery applications have not yet been filed, and the IOUs may not have filed estimates of the cost recovery in the CRTs. Further, it may be difficult to break out wildfire mitigation costs that form part of a proceeding, such as a GRC, to combine the costs with stand-alone application requests, such as recovery of wildfire mitigation memorandum accounts. A comprehensive wildfire mitigation cost tracking system, including conversion of wildfire mitigation costs to revenue requirements, could serve as a cost classification basis in future versions of the CRT.

⁹⁰ D.20-07-032, Ordering Paragraph (OP) 1, p. 99.

⁹¹ The forecasts produce cumulative rate and bill impacts, assuming recovery of all pending rate requests, for the current year and three additional years.

⁹² Forecasted incremental revenue requirement information is updated in the CRT for the duration of each cost recovery proceeding, in order to reflect the most-recently available requested revenue requirement data.

⁹³ CRTs for the large natural gas IOUs are in development.

Bundled Rate Transparency Considerations

As rates and bills produced by the CRT are occasionally shared with parties outside of the CPUC,⁹⁴ there have been inquiries into the revenue requirements and sales forecasts that comprise the rates.⁹⁵ Forecasted incremental revenue requirements modeled in the CRT are based on publicly available information; there are no transparency issues related to the availability⁹⁶ of forecasted revenue requirement data at system level. However, certain sales forecast data provided by the IOUs in their respective CRTs⁹⁷ are not available to parties outside the CPUC.

Bundled sales forecast data are available in the public domain for PG&E⁹⁸ and are not publicly-available for SCE and SDG&E.⁹⁹ Due to the confidentiality of SCE and SDG&E bundled residential sales, for interested parties without access to the CRTs, there is a lack of transparency into the revenue requirement and sales forecast that comprise an authorized bundled residential rate. This is because if the bundled residential revenue requirement is known, one can calculate the bundled residential sales forecast by solving for x in the equation:

$$\text{Rate} = \text{Authorized Revenue Requirement} / X; \quad X = \text{Authorized Revenue Requirement} / \text{Rate}$$

While not a transparency concern for the CPUC due to the CRT, transparency for stakeholders¹⁰⁰ with respect to the bundled revenue requirement and bundled sales forecast in authorized rates¹⁰¹ should be weighed against the business reasons the IOUs may have for not providing access to this data. Transparency into PG&E's bundled residential rate is clear as both the revenue requirement and sales forecast can be accessed in PG&E's rates implementation advice letters. However, there is a lack of transparency with respect to bundled sales forecast data in SCE's and SDG&E's rates implementation advice letters.

Sales forecast confidentiality treatment in each IOU's CRT, for both authorized and projected bundled sales forecasts, as well as in each IOU's rates implementation advice letters, is shown in Table 16.

⁹⁴ Parties could be members of the legislature, other state agencies, or institutions of higher learning.

⁹⁵ Rate = Revenue Requirement / Forecasted Sales.

⁹⁶ Forecasted system-level revenue requirement data is available in the rates implementation advice letters the IOUs file before a rate change.

⁹⁷ Sales forecast data in the CRT may vary from year to year.

⁹⁸ Authorized bundled sales forecasts are generally available in PG&E's rates implementation advice letters. In the CRT, PG&E's forecasting methodology for years beyond the authorized bundled sales forecast uses a projection trend of authorized bundled sales forecasts; the results do not necessarily represent PG&E's view of the sales forecast in future years.

⁹⁹ SCE's methodology uses current authorized bundled sales and internally-developed projected bundled sales forecasts, neither of which are publicly available. SDG&E's methodology uses current authorized bundled sales forecast for all years, which is not publicly available.

¹⁰⁰ Stakeholders may wish to know the amounts of the authorized bundled revenue requirement and authorized bundled forecasted sales components for various reasons, including using the authorized rate as a benchmark from which to make projections.

¹⁰¹ Authorized rates currently in effect. Prior authorized rates may not have these transparency issues.

Table 16: Bundled Sales Forecast Treatment in IOU Cost and Rate Tracking Tools

IOU	Confidentiality Labeling – Authorized Sales Forecasts	Confidentiality Labeling – Projected Sales Forecasts	Other Observations
PG&E	No confidentiality labeling	No confidentiality labeling; PG&E disclaims forecasts do not necessarily represent PG&E’s view	PG&E additionally provides full authorized sales forecast data i.e., bundled and unbundled, in each advice letter implementing rate changes.
SCE	All sales forecasts and resulting bundled residential revenue allocations labeled Confidential per D. 16-08-024 and D. 17-09-023	All sales forecasts and resulting bundled residential revenue allocations labeled Confidential per D. 16-08-024 and D. 17-09-023	SCE’s Confidentiality Declaration states that bundled customer sales forecast data is confidential and proprietary as it represents load and energy forecasts that are market sensitive under Section V of the R.05-06-040 Matrix of Allowed Confidential Treatment – IOU Data; Advice letters implementing rate changes similarly contain no bundled sales data.
SDG&E	All bundled sales forecasts and related bundled data labeled Confidential per D.06-06-066	N/A (No projected sales forecasts in CRT)	Advice letters implementing rate changes do not have bundled sales data.

While PG&E has experienced a high level of departed load, it nevertheless has maintained its transparent position about the availability of all authorized bundled sales forecast data. Presumably, PG&E has not been negatively impacted by the transparent position it has taken, as it continues to provide bundled sales data in the public domain. Accessible data is important for interested parties without access to the CRTs who may seek to understand current and projected rate trends,¹⁰² and the CPUC may want to look more closely at the possibility of requiring transparency of all authorized sales forecast data, including bundled data, for all IOUs at the rates implementation advice letter level. Advice letter bundled sales forecast consistency among the IOUs may be a first step in addressing this issue.

3.3 En Banc Bundled Residential Customer Rates Forecast Background

¹⁰² “Interested parties” could include those in higher-learning institutions as well as in other California state agencies.

The Cost and Rate En Banc rates forecast discussed below is based on bundled residential rates in keeping with CRT capability of calculating rates and bills for bundled customers.¹⁰³ Costs and rates for non-residential customer classes are not modeled in the CRTs, as usage for a typical non-residential customer needed to show bill impact is difficult to define.¹⁰⁴

Methodology and Assumptions

PG&E's, SCE's, and SDG&E's current CRT¹⁰⁵ were used as the foundation for a special-purpose 10-year rates forecast solely for use in this white paper (En Banc Bundled Residential Rates Forecast). Projected rate impacts in the En Banc Bundled Residential Rates Forecast are forecasts, including assumptions related to those forecasts, and are for illustrative purposes only. Further, forecasts are based on forward-looking estimates that are not historical facts.

Forecasts were developed for bundled residential rates for 2021 – 2030.¹⁰⁶ The forecasted rates are simple volumetric rates based on forecasted bundled residential revenue requirements and bundled residential sales forecasts. The En Banc Bundled Residential Rates Forecast methodological considerations include:

- Rates for 2021 – 2023 are based on CRT-produced rates from CRT revenue requirements¹⁰⁷ and sales forecasts.¹⁰⁸
- Rates for 2024 – 2030 are largely based on 2023 CRT revenue requirements, with escalation factors used by the California Energy Commission (CEC) in CEC rates forecasts.¹⁰⁹
- Rates for 2030 use a preliminary CEC bundled residential sales forecast developed for use in preparing the rate forecast for the *California Energy Demand Forecast Update, 2020 – 2030* (Demand

¹⁰³ The CRTs are not capable of calculating rate or bill impacts for unbundled customers.

¹⁰⁴ See Section II, sub-section, “Historical Trends in Electric Rates and Bills,” sub-heading *Residential and Select Small Commercial Bundled Average Monthly Bills*.

¹⁰⁵ PG&E and SCE's current CRTs are Fourth Quarter 2020 (Q4-2020) and SDG&E's current CRT is Third Quarter 2020 (Q3-2020).

¹⁰⁶ Actual rates at yearend 2020 are included as a reference.

¹⁰⁷ Forecasted incremental revenue requirement information is updated in the CRT for the duration of each cost recovery proceeding, in order to reflect the most-recently available requested revenue requirement data.

¹⁰⁸ CRT-produced bundled residential sales forecasts are confidential for SCE and SDG&E as indicated in the previous sub-section “Bundled Rate Transparency Considerations.”

¹⁰⁹ The CEC produces IOU service area residential rate forecasts (the weighted average of bundled, CCA, and direct access rates) as part of constructing planning area rates, which group revenue requirements in four categories: Generation, Distribution, Transmission and Other. The CEC also internally produces illustrative bundled residential rate forecasts for the three large electric IOUs. Escalation factors (presented here as multipliers) used for 2020 illustrative bundled residential rate forecasts for these categories are 1.045 percent, 1.045 percent, 1.025 percent (1.045 PG&E), and roughly 1.02 percent (i.e., inflation), respectively. PG&E transmission escalation factor 1.025 used in this analysis.

Forecast 2020), Mid-Demand Case.¹¹⁰ Bundled residential sales forecasts from 2024 – 2029 are then interpolated between 2023 sales forecasts and 2030 sales forecasts.

- Bundled residential sales forecasts from 2024 – 2030 do not include IOU-departed load expansions not known at the time the CEC rate forecast was prepared.
- Rates exclude the California Climate Credit, also known as the Greenhouse Gas (GHG) Allowance Return. The GHG Allowance Return functions as revenue requirement reduction.¹¹¹
- Rates include an estimate for the Power Charge Indifference Adjustment (PCIA), benchmarked to 2020 PCIA amounts. The PCIA functions as a revenue requirement reduction.

Baseline Scenario

The En Banc Bundled Residential Rates Forecast baseline scenario is shown in Table 17.¹¹²

Table 17: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates (nominal \$/kWh), Baseline Scenario

	Baseline Bundled Residential Electric Rate (nominal \$/kWh)										
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	\$ 0.240	\$ 0.266	\$ 0.273	\$ 0.264	\$ 0.266	\$ 0.281	\$ 0.289	\$ 0.298	\$ 0.307	\$ 0.318	\$ 0.329
SCE	\$ 0.217	\$ 0.272	\$ 0.274	\$ 0.276	\$ 0.273	\$ 0.277	\$ 0.281	\$ 0.285	\$ 0.289	\$ 0.294	\$ 0.293
SDG&E	\$ 0.302	\$ 0.300	\$ 0.328	\$ 0.338	\$ 0.340	\$ 0.355	\$ 0.371	\$ 0.388	\$ 0.405	\$ 0.424	\$ 0.443

The percentage change in forecasted 2030 bundled residential rates over 2020 rates for each IOU are:

- PG&E: 37 percent over 10 years or an annual average of 3.7 percent over this time period
- SCE: 35 percent over 10 years or an annual average of 3.5 percent over this time period
- SDG&E: 47 percent over 10 years or an annual average of 4.7 percent over this time period

¹¹⁰ The Demand Forecast Update 2020 - 2030 provides 10-year forecasts for electricity demand in California and for major utility planning areas within the state. See <https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2020-integrated-energy-policy-report-update-0>. For IOU service area residential sector rate forecasts, see 20-IEPR-03 docket, “CEDU 2020 Electricity Rate Scenarios” (January 20, 2021) at: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?doctnumber=20-IEPR-03>. The CEC also internally produces service area residential sales forecasts for the three large electric IOUs. Preliminary bundled residential sales forecasts are derived from these preliminary service area sales forecasts.

¹¹¹ This is similar to forecasted rates produced by the CEC, which also exclude the California Climate Credit.

¹¹² 2020 actual rate presented for reference. The rates in Table 17 and Figure 23 through Figure 27 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

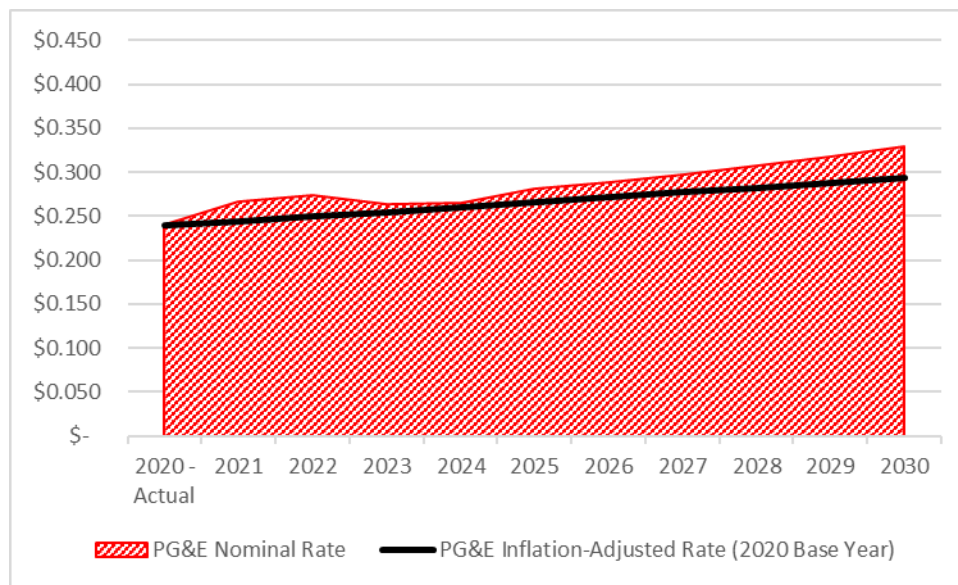
The percentage change in forecasted bundled residential rate for PG&E¹¹³ of 37 percent over 10 years is broken down by the forecasted bundled residential revenue requirement and bundled residential sales forecast changes as shown in Table 18:¹¹⁴

Table 18: PG&E 2020 Actual and 2030 Forecasted Bundled Residential Revenue Requirement and Sales Forecast, Baseline Scenario

PG&E						
2020 Actual Bundled Residential Revenue Requirement (\$ million)	2030 Forecasted Bundled Residential Revenue Requirement (\$ million)	2020 -3030 Forecasted Bundled Residential Revenue Requirement Change (%)	2020 Actual Bundled Residential Sales Forecast (GWh)	3030 Forecasted Bundled Residential Sales Forecast (GWh)	2020 -3030 Forecasted Bundled Residential Sales Change (%)	2020 -3030 Forecasted Bundled Residential Rate Change (%)
3,329	4,512	36%	13,888	13,704	(1%)	37%

Inflation-adjusted rates for each IOU, based on 2020 actual rate as the base rate, show how the bundled residential rate forecast comports with forecasted inflation.¹¹⁵ The En Banc Bundled Residential Rates Forecast baseline scenario with 2020 actual inflation-adjusted forecasted rates are shown in Figure 23 through Figure 25.

Figure 23: PG&E Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario



¹¹³ Authorized bundled residential revenue requirement and authorized bundled residential sales forecast corresponding to SCE and SDG&E 2020 actual rates are labeled confidential and not available for presentation.

¹¹⁴ 2020 actual rates at year-end.

¹¹⁵ Gross Domestic Product (GDP) inflator used for CEC Planning Area \$2019 average rates (Moody's, July 2020).

Figure 24: SCE Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario

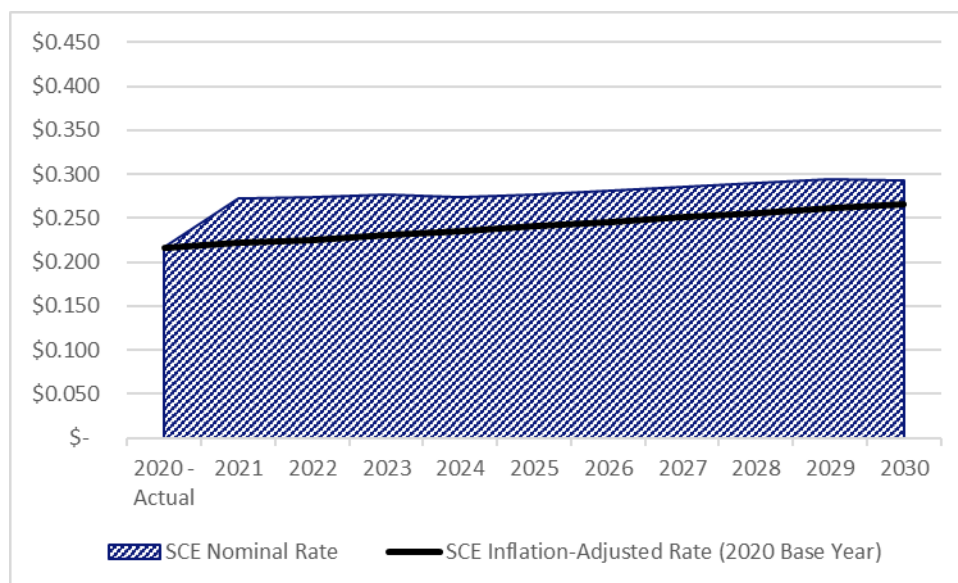
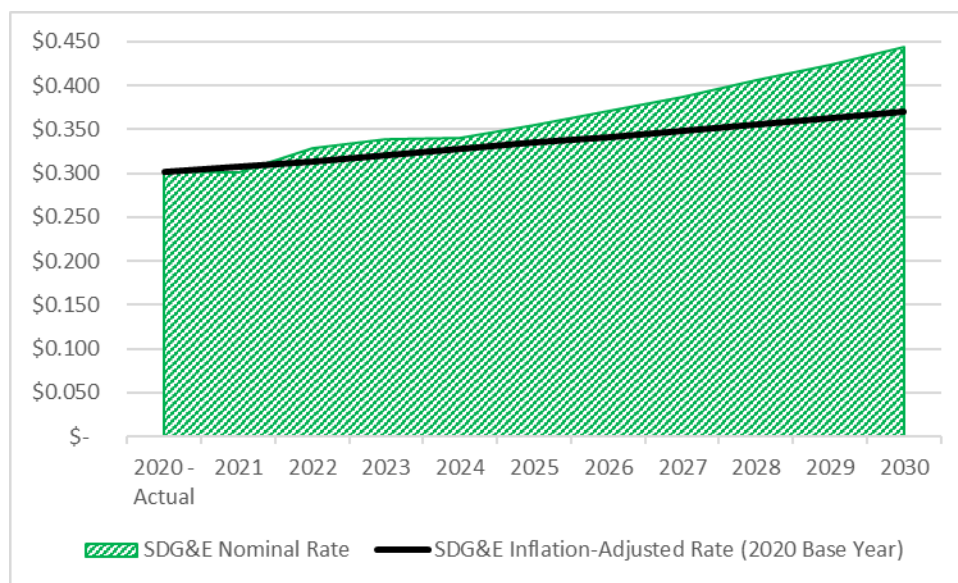


Figure 25: SDG&E Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario



The En Banc Bundled Residential Rates Forecast is shown in nominal dollars per kWh in Figure 26 and deflated to 2019 dollars per kWh i.e., 2019 real dollars,¹¹⁶ per kWh in Figure 27.

Figure 26: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates (nominal \$/kWh), Baseline Scenario

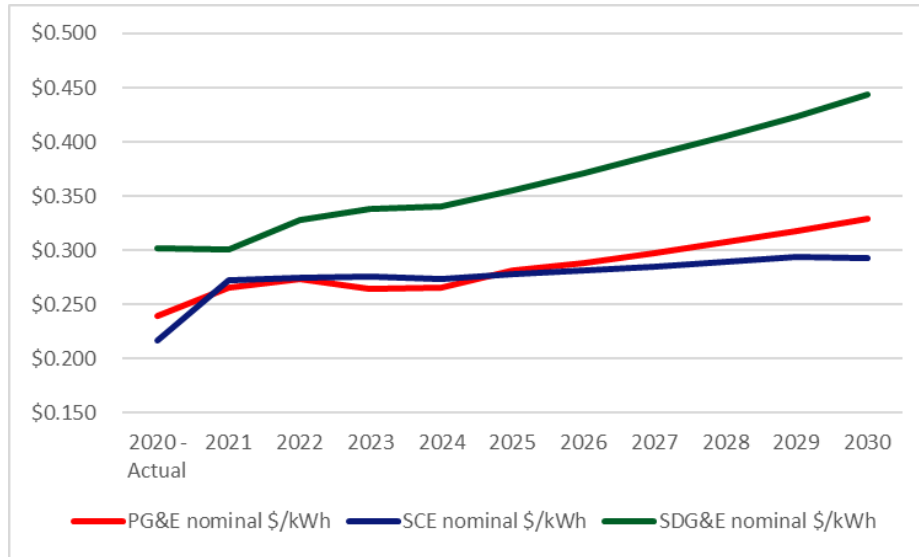
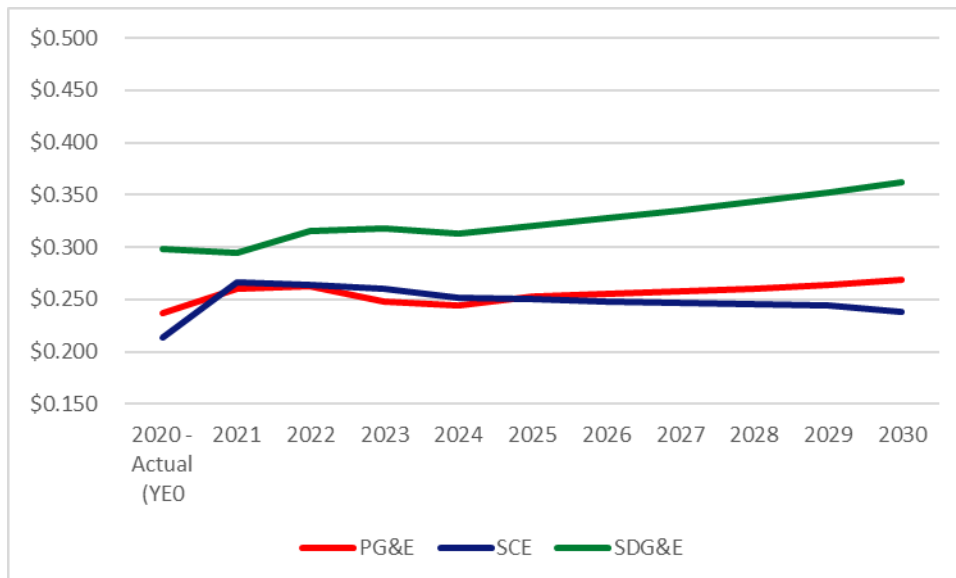


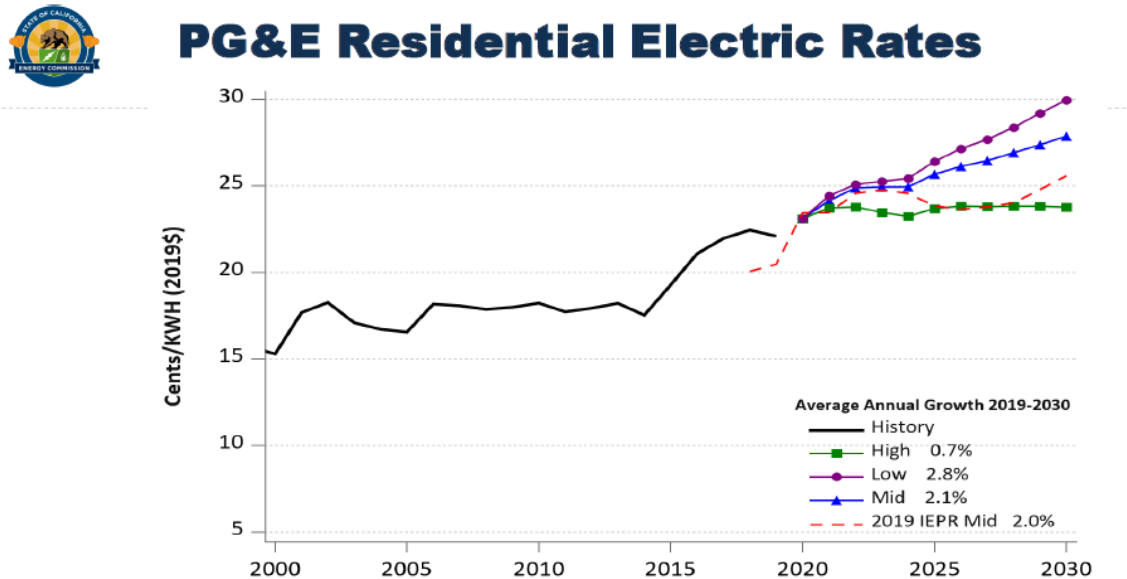
Figure 27: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates (\$2019/kWh), Baseline Scenario



CEC 2020 IEPR Planning Area Residential Average Rate Scenarios

Residential average rates for PG&E, SCE, and SDG&E **planning areas** were filed by the California Energy Commission (CEC) in the 2020 Integrated Energy Policy Report (IEPR) docket.¹¹⁷ Planning area rates are the weighted average for all utilities in the planning area, e.g., IOUs and Publicly-Owned Utilities (POU).¹¹⁸ Figure 28 through Figure 30 show these residential rates in 2019 dollars.¹¹⁹ The blue line shows the mid-demand case.

Figure 28: CEC 2020 IEPR Planning Area Residential Rates Scenarios, PG&E



¹¹⁶ \$2019 dollars uses Gross Domestic Product (GDP) deflator used for CEC Planning Area \$2019 average rates (Moody's, July 2020).

¹¹⁷ See 20-IEPR-03 docket, "Electric Rate Scenarios" (August 25, 2020) at:

<https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03> .

¹¹⁸ Planning area rates are not directly comparable with IOU service area rates due to the inclusion of revenue requirement of the POU.

¹¹⁹ Adjusted to nominal dollars, the planning area mid-demand case residential rates (kWh) for PG&E, SCE, and SDG&E in 2030 are: PG&E \$0.342; SCE \$0.242; SDG&E \$0.348.

Figure 29: CEC 2020 IEPR Planning Area Residential Rates Scenarios, SCE



SCE Residential Electric Rates

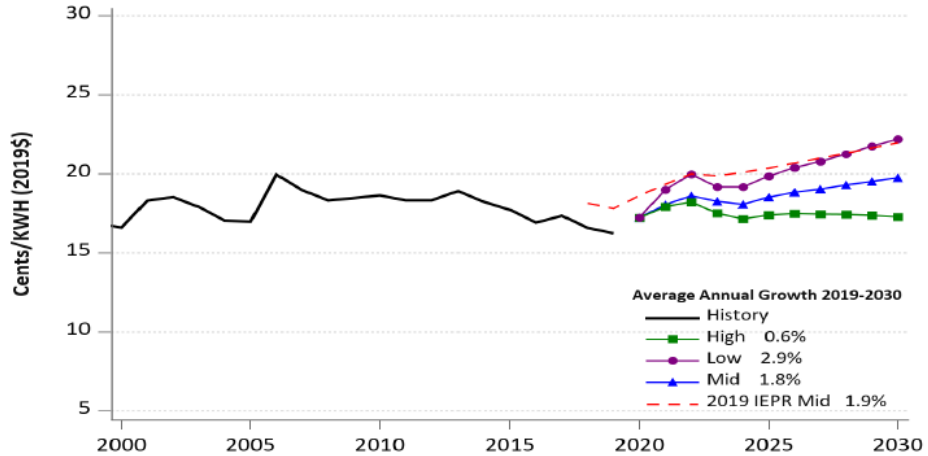
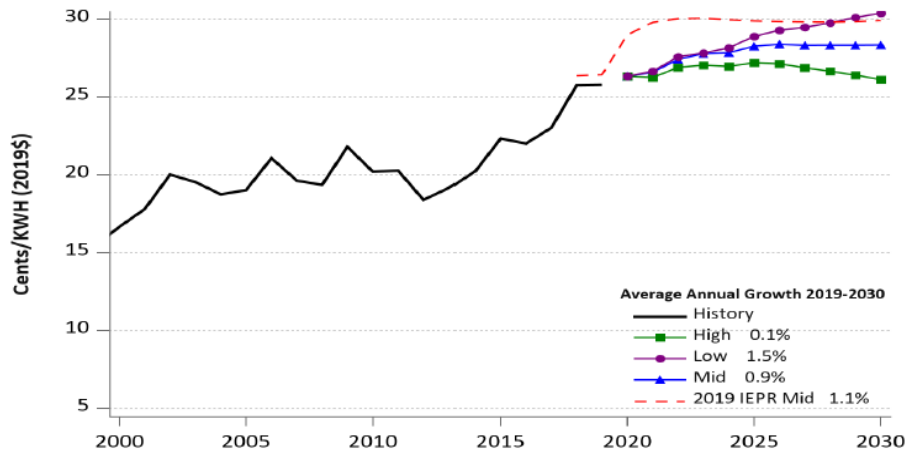


Figure 30: CEC 2020 IEPR Planning Area Residential Rates Scenarios, SDG&E



SDG&E Residential Electric Rates



The CEC 2020 IPER residential rates planning area forecast uses IOU revenue requirement as originally filed with the CEC for the 2019 IEPR¹²⁰ updated with CPUC Energy Division CRT data as a base, with adjustments, and a 4.5 percent escalator for the mid-demand case distribution revenue requirement for years 2025 – 2030. This 2020 escalator assumption is higher than that used in the 2019 IEPR to reflect increased spending for wildfire mitigation, grid modernization, and electrification.¹²¹

¹²⁰ The IOUs file these revenue requirements on CEC Form 8.1.

¹²¹ Generation is updated using wholesale electricity prices from 2019 IEPR PLEXOS results.

CEC 2020 IEPR Service Area Residential Average Rate Scenarios and CPUC Forecasted Bundled Residential Rates

Before comparing CEC preliminary bundled residential rates with CPUC forecasted bundled residential rates, adjustments must be made to account for the PCIA. The PCIA is the mechanism used to ensure that the creation of Community Choice Aggregators (CCA) does not result in cost increases for bundled customers. While the PCIA has no impact on system average rates (which includes both CCA and bundled customers), it has the impact of lowering overall rates for bundled customers. As previously indicated, CPUC forecasted bundled residential rates include an estimate for the PCIA, which lowers the revenue requirement for which the bundled residential class is responsible. However, CEC planning area forecasted residential rates don't consider PCIA as an input, as CEC forecast models run at the service area level and reflect a system average rate.

To account for this difference and also to facilitate a more direct comparison, it is better to compare the CEC preliminary bundled residential rates with the CPUC forecasted bundled residential rates. The CEC produces IOU service area residential rate forecasts (the weighted average of bundled, CCA, and direct access rates) as part of constructing IEPR planning area rates. Further, service area residential rate forecasts can be used to produce illustrative bundled residential rate forecasts for the three large electric IOUs.¹²² Table 19 compares the CEC preliminary forecasted bundled residential rate, adjusted for the PCIA revenue reduction, with the CPUC forecasted bundled residential rate in 2030 for each of the IOUs.¹²³

¹²² The CEC also internally produces illustrative bundled residential rate forecasts for the three large electric IOUs.

¹²³ The rates in the CPUC Forecasted Bundled Residential Rate column match the 2030 rates in Table 17.

Table 19: CEC Preliminary and CPUC Forecasted Bundled Residential Rate Comparison (2030)

	CEC Preliminary Bundled Residential Rate, Unadjusted (\$/kWh) 2030	CEC Preliminary Bundled Residential Rate, Adjusted for PCIA revenue reduction (\$/kWh) 2030	CPUC Forecasted Bundled Residential Rate (\$/kWh) 2030
PG&E	0.347	0.314	0.329
SCE	0.244	0.213	0.293
SDG&E	0.341	0.314	0.443

The 2030 rate comparison shows similar CPUC forecasted rates to the CEC preliminary rates for PG&E. However, SCE and SDG&E 2030 CPUC forecasted rates are not similar to the preliminary forecasted rates. The difference in both cases is due to a higher revenue requirement in the CPUC forecasted bundled residential rate. The level-setting of the revenue requirement in 2024 to 2023 CRT revenue requirement, per the previously indicated methodology, is the primary reason that the CPUC forecasted bundled residential rate revenue requirement is higher. The CPUC forecasted system-level revenue requirement and bundled residential revenue requirement in 2030 for each of the IOUs is shown in Table 20.

Table 20: CPUC Forecasted Bundled Residential Rate Comparison (2030)

	Forecasted System-Level Revenue Requirement 2030	Forecasted Bundled Residential Revenue Requirement 2030
PG&E	\$21.5 billion	\$4.5 billion
SCE	\$20.3 billion	\$6.4 billion
SDG&E	\$5.1 billion	\$2.3 billion

Key to 2030 forecasted bundled residential rates is the projected sales forecast underlying the bundled residential rates. The CPUC forecasted bundled residential rates reflect an estimate based on a preliminary CEC bundled residential sales forecast.¹²⁴ It must be emphasized that forecast reliability decreases the further out the time horizon, with accuracy of 2030 forecasted rates necessarily less than that of 2021.

The En Banc Rates Forecast baseline scenario sets the baseline rates from which further rate analysis in this white paper will be based. The baseline scenario and the wildfire high-cost scenario used in a later section of this paper are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

3.4 Wildfire Mitigation Plan Projected Costs

The IOUs provide the CPUC with their anticipated wildfire mitigation spending in various proceedings, including Wildfire Mitigation Plans, General Rate Cases (GRC) and the Risk Assessment Mitigation Phase (RAMP) of the GRC, among others. The IOUs file GRC applications on a staggered schedule, therefore the

most recent data available for most of the IOUs is their latest WMP. The most recently filed WMPs at the time of the preparation of this paper were prepared as part of the 2020 WMP filings in February 2020 and included spending estimates for calendar years 2020-2022. In order to develop estimates for this paper, the IOUs were asked to provide wildfire mitigation spending estimates through 2030. All the IOUs responded that they were unable to provide reliable data beyond what had been publicly shared to date. The IOUs asserted that wildfire mitigation is not a predictable effort at this time, as they operate with the intention of letting lessons learned each year determine next year's effort. In some instances, the IOUs provided considerations that are expected to have an impact on their long-term planning but declined to provide detailed forecasts.

In the absence of detailed information from the IOUs, the forecasts generally incorporate known program changes and assume a small escalation factor for remaining activities. For the purposes of this exercise, the forecast also assumes pending applications related to wildfire are approved at the level of recovery requested and excludes wildfire-related transmission costs, which would overlap with the transmission costs discussed separately in this paper. In developing the forecast, Energy Division staff also consulted with Wildfire Safety Division Staff for input on expected trends in wildfire mitigation activities. Details on the forecast assumptions for each IOU are described below. The assumptions detailed below are not intended to reflect precise anticipated spending or predetermine what the CPUC may grant for recovery.

Baseline Scenario Assumptions of Wildfire Mitigation Plan Costs

PG&E

PG&E's forecast is based on a data request response that projects wildfire spending to 2026 consistent with data in its most recent RAMP filing. PG&E aggregates its mitigations into large generic programs such as "System Hardening" and reports data at that program level. This presents challenges to adjusting the forecast in the out years for individual programs. Therefore, for years beyond 2026, the forecast assumes a two percent annual increase in revenue requirement for wildfire spending.

SCE

SCE's forecast uses as its basis estimates from the 2020 WMP filing and 2023 request from the Test Year 2021 GRC filing. To estimate years 2024 through 2026, the forecast uses a five-year average of a combination of recorded and forecast data for 2019-2023.¹²⁴ The CPUC commonly uses a five-year average to forecast costs in GRC proceedings. While the five-year average methodology typically uses all recorded data, many of the IOUs wildfire mitigation programs were adopted in response to SB 901 (Dodd, 2018), AB 1054 (Holden, 2019), and the WMP process, and therefore data before 2018-2019 are unlikely to be

¹²⁴ As part of this process, CEC service area sales are estimated by benchmarking to 2019 actual service area sales, using a planning area sales forecast growth escalation. The CEC also internally produces illustrative bundled residential rate forecasts for the three large electric IOUs.

¹²⁵ As Energy Division does not have a tool to convert SCE's capital costs to revenue requirement equivalent, estimates were used for this conversion. Capital cost conversions may include ongoing capital-related revenue requirements from previous capital expenditures.

predictive of future spending. Consistent with PG&E's estimates, the forecast assumes a two percent annual increase each year between 2027 and 2030.

The forecast includes exceptions to the five-year average and escalation methodology for SCE's most expensive activity, the Wildfire Covered Conductor Program.¹²⁶ SCE's 2020 WMP indicates plans to significantly ramp-up covered conductor installation in its High Fire Risk Areas (HFRA) over the first half of the decade, at which time SCE anticipates having addressed 70 percent of the overhead wire originally in scope as part of its 2018 Grid Safety & Resiliency Plan. In consultation with the CPUC's Wildfire Safety Division, the forecast assumes increases above the 2022 projection of an average seven percent per year through 2025, then remaining steady over the following five years as technology and installation becomes more standardized and SCE replaces remaining high-risk circuits in its HFRA. The overall total would also likely be capped by overhead line miles in High Fire Threat District (HFTD) areas.¹²⁷ SCE has about 14,500 overhead miles in HFTD areas. The forecast estimates approximately two-thirds of those lines being replaced by covered conductor (i.e., insulated power lines).

SCE's covered conductor program is likely to impact its distribution pole replacement estimates, as installation of covered conductors often requires concurrent replacement of poles, and crossarms due to increased weight from insulation. Accordingly, as SCE ramps up its covered conductor installation, the forecast assumes distribution pole replacement costs to equally increase and then plateau in line with the covered conductor installations.

As with all other programs, the Wildfire Covered Conductor Program estimates are subject to change as more data become available regarding effectiveness.

SDG&E

The basis for SDG&E's wildfire mitigation costs is the 2020 WMP estimates for 2020-2022. The forecast for 2023-2030 is based on SDG&E 2022 amounts as filed in the 2020 WMP, with adjustments to the capital system hardening program estimates.¹²⁸

SDG&E allocates a significant portion of the spending in its 2020 WMP toward undergrounding. In consultation with the Wildfire Safety Division, the forecast for undergrounding significantly ramps up over the next WMP plan period (2023-2025) and then slowly tapers off as the majority of riskier circuits that may justify the need for undergrounding are replaced and there is less remaining circuitry that qualifies.

The forecast for overhead hardening and pole replacement in 2023-2030 utilizes a five-year average of combined recorded and estimated costs for 2019-2022. There are also two adjustments to reflect the

¹²⁶ Covered conductor is aluminum or copper wire covered by three layers of insulation designed to withstand incidental contact from foreign objects, such as vegetation, other debris, and the ground in wire down events.

¹²⁷ "High Fire Threat Districts" are designated by CPUC in R.15-05-006. "High Fire Risk Areas" are an internal SCE designation based on a combination of its historical map boundaries (based on past fire management and response experiences), CAL FIRE's Fire Hazard Severity Zone (FHSZ) maps, and most recently, the CPUC's HFTD maps released in January 2018. SCE has since considered Zone 1, Tier 2 and Tier 3 (collectively, the HFTD), and non-CPUC historical high fire risk areas, to collectively be "HFRA." See SCE's 2020 WMP for more information.

¹²⁸ As Energy Division does not have a tool to convert SDG&E's capital costs to revenue requirement equivalent, estimates were used for this conversion. Capital cost conversions may include ongoing capital-related revenue requirements from previous capital expenditures.

completion of work on two projects, namely beginning in 2022 for the system hardening project in the Cleveland National Forest and beginning in 2023 and for expulsion fuse replacement, as specified in the 2020 WMP.

Baseline Scenario Assumptions of Wildfire Insurance and Catastrophic Event Costs

The CPUC allows the IOUs to recover certain wildfire-related costs that are external to the activities described in the WMP, including for wildfire insurance premiums and catastrophic events. Wildfire insurance costs that are incremental to the insurance costs authorized in the GRCs may be tracked for recovery through the Wildfire Expense Memorandum Account (WEMA) for PG&E and SCE, and the Liability Insurance Premiums Balancing Account (LIPBA) for SDG&E. The IOUs also track eligible costs to respond to catastrophic events, including wildfire, in their Catastrophic Event Memorandum Accounts (CEMA).

To estimate future costs for wildfire insurance and catastrophic events, the baseline scenario includes the average costs requested in applications over the last three years, 2018-2020. The last three years were used to reflect the period of time since SB 901 was enacted.

For PG&E and SCE, the forecast for wildfire insurance and catastrophic events costs is based on the average requested cost recovery between 2018-2020 for CEMA and WEMA applications.¹²⁹ The forecast assumes the IOUs will request these amounts for recovery in applications filed annually beginning in 2021, which would begin to impact rates in 2023 through 2030. Given the magnitude of these costs, the forecast assumes a two-year recovery period for each application.

SDG&E does not have any CEMA cost recovery applications during this time period but requested recovery of the 2020 under-collection in its LIPBA beginning in 2021. The forecast assumes the 2020 under-collection of \$59.8 million will be an annual recurring cost from 2021 to 2030. The forecast does not assume additional liability claims costs beyond those included in the wildfire insurance premiums forecast in the WEMA and the AB 1054 Wildfire Fund, discussed in the previous section of this paper on historic wildfire costs. If wildfire claims exceed the amounts covered by insurance and the Wildfire Fund, PG&E and SCE may track incremental liability claims in their WEMAs. The amount that would ultimately be approved for rate recovery depends on the CPUC's reasonableness determination and is unknown at this time.

It is possible that these costs could decrease over time as a result of system hardening activities and efforts by the Legislature to support a pooled insurance fund. On the other hand, the recent trend of increasingly catastrophic wildfires could result in costs that exceed the historical average. The assumptions in the forecast assume the costs requested in recent years continue at a similar level, however these assumptions are not intended to reflect exact anticipated spending, given the uncertainties.

¹²⁹ SCE's estimate also includes incremental wildfire insurance premium costs requested in Advice Letter 3768-E in 2018.

Wildfire High-Cost Scenario Assumptions

As previously discussed, there is significant uncertainty surrounding the actual level of IOU spending on wildfire mitigation over the next 10 years. The last full year of wildfire mitigation spending data available during the preparation of this paper was for calendar year 2019. In comparing planned 2019 to actual 2019 spending, each IOU recorded significantly higher costs than estimated. PG&E planned to spend \$2.5 billion and recorded \$3 billion (19 percent higher). SCE planned to spend \$671 million and recorded \$1.6 billion (132 percent higher). SDG&E planned to spend \$219.9 million and recorded \$306.7 million (40 percent higher). These figures suggest actual spending may be higher than forecast in future years.

Further, the CPUC has acknowledged the difficulty in developing accurate forecasts for wildfire spending by allowing balancing account treatment that permits recovery of additional amounts above the authorized budget. For example, in PG&E's recent GRC Decision (D.) 20-12-005, the CPUC allows PG&E to recover up to 115 percent of the authorized budget tracked in the Wildfire Mitigation Balancing Account and 120 percent of the budget tracked in the Vegetation Management Balancing Account. Similarly, the CPUC approved SCE's Grid Safety & Resiliency Program in proceeding D.20-04-013, which adopted a settlement agreement that includes an allowance for recovery of up to 115 percent for the covered conductor program budget.

To develop a high-cost scenario for wildfire mitigation costs in this paper, the forecast assumes a 20 percent adder starting in 2023 for wildfire mitigation estimates to account for uncertainties such as increased spending and cost overruns. The 20 percent adder is applied to wildfire insurance and catastrophic events costs as well. Together, wildfire mitigation and wildfire insurance (and catastrophic events) are referred to as "wildfire costs." These assumptions are not intended to suggest an expected outcome but are developed for the purposes of showing the potential impact of such spending on customer rates and bills.

2020-2030 Estimated Wildfire Costs

Baseline Scenario

Baseline total incremental revenue requirement resulting from wildfire costs between 2021 and 2030 for each of the IOUs are estimated as follows:

- PG&E: \$20.2 billion
- SCE: \$14.8 billion
- SDG&E: \$ 3.9 billion

Forecasted revenue requirements in 2030 for estimated wildfire costs at system-level and for bundled residential are show in Table 21.

Table 21: Forecasted Wildfire Revenue Requirements, System-Level and Bundled Residential (2030)

	Forecasted Wildfire Revenue Requirement: System Level 2030	Forecasted Wildfire Revenue Requirement: Residential Level (Bundled) 2030
PG&E	\$2.2 billion	\$380 million
SCE	\$1.7 billion	\$385 million
SDG&E	\$418 million	\$145 million

The forecasted wildfire bundled residential revenue requirement produces the forecasted wildfire rate embedded in the forecasted baseline bundled residential rate as shown in the lower portion of Table 22. For convenience, the forecasted baseline bundled residential rate is shown in the upper portion of the figure.¹³⁰

Table 22: Forecasted Wildfire Rate Embedded in Baseline Bundled Residential Rate Forecast (nominal \$/kWh)

	Baseline Bundled Residential Electric Rate (nominal \$/kWh)										
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	\$ 0.240	\$ 0.266	\$ 0.273	\$ 0.264	\$ 0.266	\$ 0.281	\$ 0.289	\$ 0.298	\$ 0.307	\$ 0.318	\$ 0.329
SCE	\$ 0.217	\$ 0.272	\$ 0.274	\$ 0.276	\$ 0.273	\$ 0.277	\$ 0.281	\$ 0.285	\$ 0.289	\$ 0.294	\$ 0.293
SDG&E	\$ 0.302	\$ 0.300	\$ 0.328	\$ 0.338	\$ 0.340	\$ 0.355	\$ 0.371	\$ 0.388	\$ 0.405	\$ 0.424	\$ 0.443

	Wildfire Rate Embedded in Baseline Bundled Residential Electric Rate (nominal \$/kWh)										
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	\$ 0.004	\$ 0.016	\$ 0.021	\$ 0.021	\$ 0.034	\$ 0.035	\$ 0.027	\$ 0.027	\$ 0.027	\$ 0.028	\$ 0.028
SCE	\$ 0.007	\$ 0.024	\$ 0.022	\$ 0.015	\$ 0.021	\$ 0.023	\$ 0.026	\$ 0.026	\$ 0.026	\$ 0.025	\$ 0.025
SDG&E	\$ 0.010	\$ 0.019	\$ 0.021	\$ 0.024	\$ 0.027	\$ 0.028	\$ 0.029	\$ 0.030	\$ 0.030	\$ 0.030	\$ 0.029

To get an idea of the portion of the monthly bill that corresponds to wildfire costs, a comparison is made between the wildfire portion of the forecasted monthly bills in 2021 and 2030 for each IOU, along with a total bill comparison, as shown in Table 23. The forecasted rates are multiplied by the usage amounts that the IOUs use in their legal bill inserts – 500 kWh per month for PG&E, SCE, and SDG&E.¹³¹

¹³⁰ The rates in the upper portion of Table 22 match the rates in Table 17. Similar to Table 17, the rates in Table 22 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

¹³¹ In compliance with Rule 3.2 (d) of the CPUC’s Rules of Practice and Procedure, the IOUs are to provide notice of, among other things, proposed residential rate changes addressed in a utility’s application. Bill impacts for a typical residential customer usually accompany these rate changes in a bill insert sent to customers known as the “legal bill insert.” Usage data here is that used in legal bill inserts for PG&E’s 2020 GRC Phase II, SCE’s 2021 GRC Phase II, and SDG&E’s 2019 GRC Phase II applications. Bills are for illustrative purposes only.

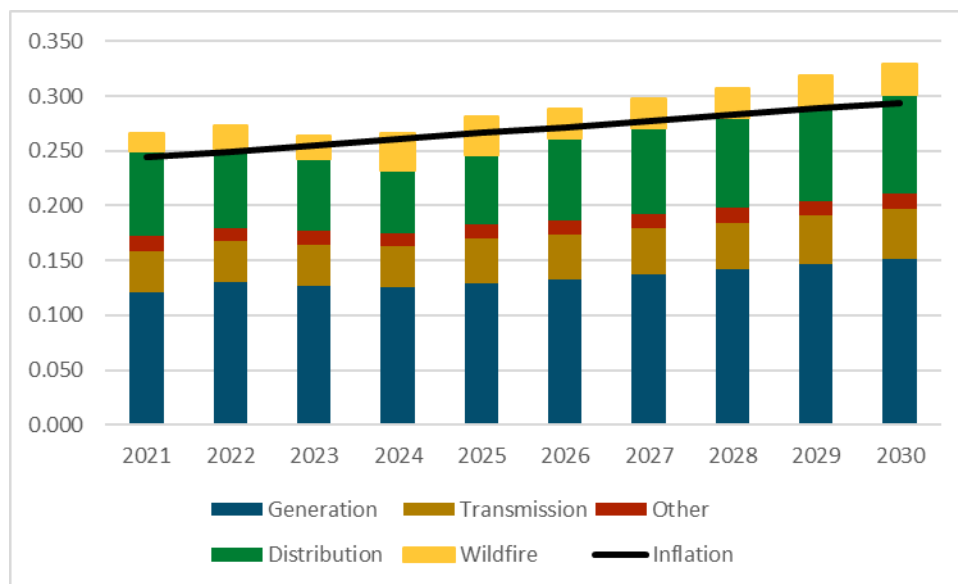
Table 23: Wildfire Portion of Monthly Bill and Total Monthly Bill, Bundled Residential Customers (nominal \$/month)

	2021			2030		
	Wildfire Portion (\$/month)	Total Bill (\$/month)	Wildfire Portion (%)	Wildfire Portion (\$/month)	Total Bill (\$/month)	Wildfire Portion (%)
PG&E	8.00	133.00	6.0%	14.00	164.50	8.5%
SCE	12.00	136.00	8.8%	12.50	162.00	7.7%
SDG&E	9.50	150.00	6.3%	14.50	221.50	6.5%

For all of the IOUs, the wildfire mitigation programs estimated to contribute most significantly to cost increases in 2030 are vegetation management and system hardening, including undergrounding and replacing bare overhead conductors with covered conductors.

The rate attributable to wildfire costs is embedded in the baseline bundled residential rate;¹³² however, it can be viewed separately from the non-wildfire portion of the rate¹³³ as shown in Figure 31 through Figure 33.¹³⁴ The inflation-adjusted forecasted rate line is based on 2020 actual rates. For all embedded rate components by \$/kWh, see Appendix B.

Figure 31: PG&E Forecasted Bundled Residential Rates (\$ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



¹³² The wildfire rate is included as a component of the distribution rate.

Figure 32: SCE Forecasted Bundled Residential Rates (\$ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate

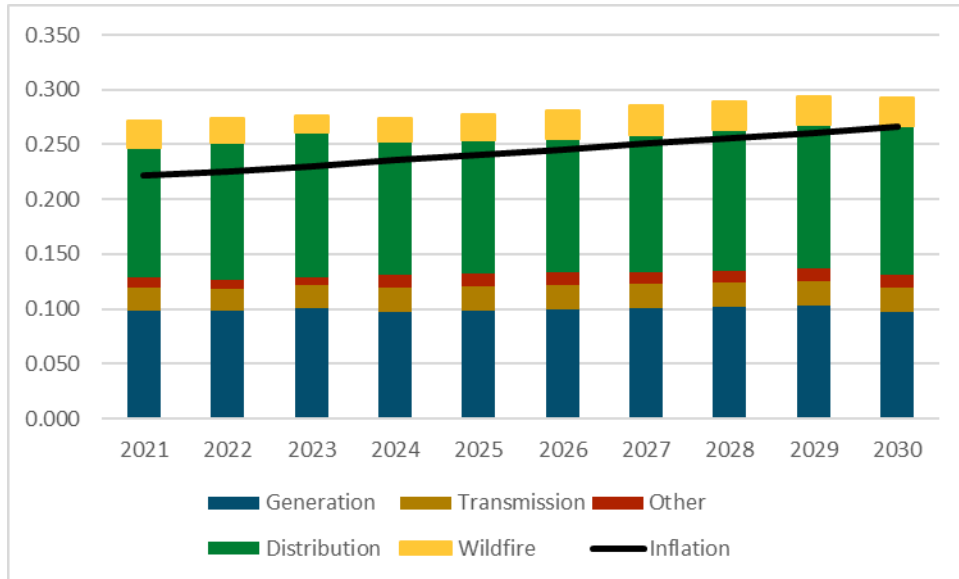
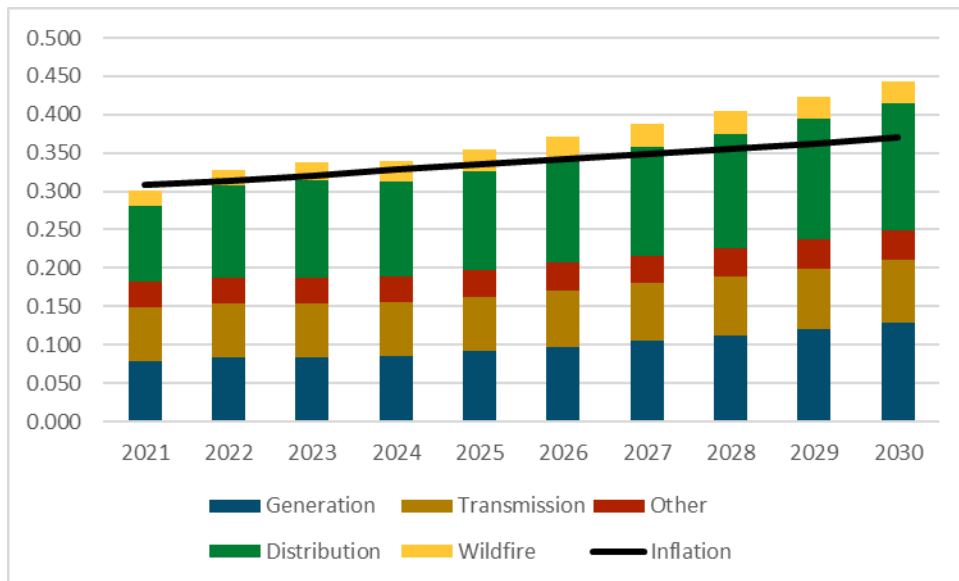


Figure 33: SDG&E Forecasted Bundled Residential Rates (\$ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



Wildfire High-Cost Scenario

¹³³ The rates in Figure 31 through Figure 33 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

¹³⁴ From a theoretical standpoint, the non-wildfire rate portion could be called a counterfactual wildfire rate i.e., the rate if no wildfire costs were included.

Estimated total incremental revenue requirement, including the high-cost wildfire adder, between 2021 and 2030 for each of the IOUs are:

- PG&E: \$23.7 billion
- SCE: \$17.2 billion
- SDG&E: \$ 4.6 billion

Unlike wildfire costs in the baseline scenario which are embedded in the rates forecast, the wildfire high-cost scenario uses a 20 percent adder which boosts the overall revenue requirement compared to that in the baseline scenario.¹³⁵ Forecasted revenue requirements in 2030 for estimated wildfire costs at system-level and for bundled residential are show in Table 24.

Table 24: Forecasted High-Cost Wildfire Revenue Requirements, System-Level and Bundled Residential (2030)

	Forecasted High-Cost Wildfire Revenue Requirement: System Level 2030	Forecasted High-Cost Wildfire Revenue Requirement: Residential Level (Bundled) 2030
PG&E	\$2.6 billion	\$456 million
SCE	\$2.1 billion	\$462 million
SDG&E	\$502 million	\$174 million

The forecasted high-cost wildfire bundled residential revenue requirement is reflected in the forecasted rates shown in Table 25.¹³⁶

Table 25: Forecasted Bundled Residential Electric Rate with High-Cost Wildfire Adder (nominal \$/kWh)

	Bundled Residential Electric Rate with High-Cost Wildfire Adder (nominal \$/kWh)										
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
PG&E	0.266	0.273	0.268	0.272	0.288	0.294	0.303	0.313	0.324	0.335	
SCE	0.272	0.274	0.279	0.278	0.282	0.286	0.290	0.294	0.299	0.298	
SDG&E	0.300	0.328	0.343	0.346	0.361	0.377	0.394	0.411	0.430	0.449	

The tables above offer insight into the rate impacts associated with increasing levels of wildfire mitigation spending. However, many questions remain regarding what constitutes a sufficient level of spending on wildfire mitigation. The actual wildfire risk reduction and performance of many of the utility proposed programs are currently unknown.

As part of the annual Wildfire Mitigation Plan review process, the CPUC and Wildfire Safety Division continue to refine the evaluation of IOU wildfire mitigation activities. The WMP review process requires the IOUs to submit specific details and supporting information to evaluate the efficacy of individual initiatives.

¹³⁵ The 20 percent adder applies to the distribution rate only.

¹³⁶ The rates in Table 25 are intended solely to facilitate discussion related to white paper and are not to be used for any other purpose.

More data on risk reduction capabilities and performance of wildfire mitigation measures will inform CPUC decision-making regarding the costs and levels of deployment of various wildfire mitigation measures, consistent with just and reasonable rates.

Future decisions related to the timeline and method, such as securitization of wildfire-related cost recovery, will affect how the wildfire mitigation costs ultimately impact customer bills. In coming years, we can expect more predictable levels of spending as initial programs are completed and the risk reduction potential of various programs are validated.

3.5 Transportation Electrification Programs Projected Cost Background

While the number of EVs on the road has increased significantly in recent years, rapid growth in sales is expected over the next decade. As battery and vehicle costs decline, EV adoption will expand beyond early adopters to the broader population of vehicle owners, as well as other sectors of vehicles such as buses, delivery fleets, and off-road vehicles such as farm equipment, to meet California’s ambitious climate and TE goals.

To further this transition, CPUC staff issued a draft Transportation Electrification Framework (TEF) in 2020.¹³⁷ In 2021, the CPUC may adopt recommendations from the TEF, which would, among other things:

- Require the IOUs to undertake a TE planning and prioritization process to ensure that electric infrastructure will be able to support a large influx of new EVs.
- Resolve policy issues previously raised on a case-by-case basis, including issues pertaining to cost recovery.
- Allow for more streamlined pilot and program review.
- Provide a signal to third-party market participants about the IOUs’ role in meeting the state’s goals and managing the electric grid.

Adopting the TEF as currently proposed would set the stage for the IOUs to propose future programs to support TE goals. At this juncture, the scale and cost of any such programs are unknown and will be subject to review in the context of the IOUs’ long-term Transportation Electrification Plans envisioned by the TEF, as well as other planning endeavors, such as the Integrated Resource Planning process to ensure that the proper generation resources are available to support increased electricity demand from EVs.

More broadly, California will be undertaking a tremendous effort to accelerate TE infrastructure deployment in the coming years to meet the state’s TE goals. The scale of the challenge is highlighted in the recently issued CEC Staff report *Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment*, which notes that 1.5 million chargers will be needed by 2030 to support Governor Newsom’s goals for light-duty

¹³⁷ See “Transportation Electrification Framework – Energy Division Staff Proposal” Issued via Ruling, February 3, 2020. Weblink can be accessed at: <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=326172086>

vehicles. Considering that the state had 188,000 public chargers installed or planned as of September 30, 2020, there is a substantial gap in public charging infrastructure that will need to be funded through a combination of ratepayer, private, and public (e.g., state/federal grant) funding.¹³⁸ While the report urges continued public financing of chargers and infrastructure in the near-term, it also highlights the importance of devising innovative financing mechanisms that can reduce the burden of these investments on ratepayers and the public, and for finding ways to utilize charging infrastructure to benefit the grid, and thus potentially reduce infrastructure upgrade costs elsewhere. Examples of public funding include:

- **CEC California Electric Vehicle Infrastructure Project (CALeVIP):** an incentive program that provides funds for EV charger installations across the state. CALeVIP is currently funded for \$124.9 million through CEC funding, with \$32 million in co-funding partner contributions.¹³⁹
- **IOU Charging Infrastructure Programs:** much of the ratepayer (i.e., public) funding allocated for IOU-led TE activities is being used to support the construction of shared or public charging infrastructure.
- **Innovative Public Financing:** Governor Newsom’s proposed budget for 2021-2022 includes a proposal to securitize \$1 billion in future revenue / vehicle registration fees, a portion of which would be used for loans to leverage private sector capital towards the construction of charging infrastructure.¹⁴⁰
- **Low Carbon Fuel Standard (LCFS):** credit revenue generated from the use of EVs is used in many cases to support additional charging infrastructure.

Baseline Scenario Assumptions of Transportation Electrification Program Costs

IOU TE programs and infrastructure upgrades are primarily recovered through rates. As the CPUC is actively deliberating the magnitude of potential investments in TE and the degree of responsibility for IOU ratepayers to cover those costs over the next decade, we refrain from detailed speculation regarding future investments by IOUs. Rather, this analysis presents cost estimates based on existing IOU spending on TE. This approach allows for an examination of the impact of current programs on rates, and a simple doubling of program spending in the latter half of the decade.¹⁴¹

¹³⁸ Crisostomo, Noel, Wendell Krell, Jeffrey Lu, and Raja Ramesh. January 2021. Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030. California Energy Commission. Publication Number: CEC-600-2021-001.

¹³⁹ <https://calevip.org/about-calevip>

¹⁴⁰ <http://www.ebudget.ca.gov/budget/2021-22/#/BudgetSummary>

¹⁴¹ This approach may not reflect the outcome of forthcoming IOU planning endeavors for TE that result from the TEF.

2020-2030 Estimated Transportation Electrification Costs

The baseline forecast assumes an incremental revenue requirement resulting from TE programs between 2021 to 2030 of \$2.8 billion across SCE, SDG&E, and PG&E. This forecast is based on the following inputs and assumptions:

- Existing CPUC-approved TE programs.¹⁴²
- SDG&E’s pending application for Power Your Drive 2.¹⁴³
- Projected 2030 incremental revenue requirements for TE – this includes ongoing capital-related revenue requirement for existing programs, plus rough estimates for incremental program revenue requirements.
 - The rough estimates were obtained by doubling the 2023 forecasted incremental revenue requirement, based on a near-doubling of electrification load that would correspond to a doubling in annualized costs for electrification program/infrastructure, as shown in the 2019 IEPR.¹⁴⁴
- Growth formula – interpolation of the forecasted incremental revenue requirement is used to determine the revenue requirement between the years 2023 and 2030. A simple percentage growth formula is used to accomplish this.¹⁴⁵

Forecasted revenue requirements in 2030 for estimated transportation costs at system-level and for bundled residential are show in Table 26.

Table 26: Forecasted Transportation Electrification Revenue Requirements, System-Level and Bundled Residential (2030)

	Forecasted Transportation Electrification Revenue Requirement: System Level 2030	Forecasted Transportation Electrification Revenue Requirement: Residential Level (Bundled) 2030
PG&E	\$115 million	\$20 million
SCE	\$224 million	\$50 million
SDG&E	\$81 million	\$28 million

¹⁴² IOUs provided forecasted incremental revenue requirements through 2023 via data request.

¹⁴³ *Id.*

¹⁴⁴ The CEC’s 2019 IEPR forecasts CAISO-wide electric sales due to electrification growing from 7.8 TWh in 2023 to 14.6 TWh in 2030. This projected CAISO-wide growth is largely a result of TE, with approximately 90 percent associated with TE and 10 percent associated with “other electrification.”

¹⁴⁵ The simple percentage growth methodology assumes equal revenue requirement for each year between 2023 and 2030. This results in smaller percentage changes each year as the interval revenue requirement is calculated over an increasingly larger base. First year percentage growth is about 14 percent.

To calculate a baseline bundled residential rate forecast, we used the forecasted revenue requirement in 2030 and a CEC-driven electricity sales forecast, shown in the upper portion of Table 27.¹⁴⁶ The baseline TE rate embedded in these total rates is broken out in the lower portion of the Table 27.

Table 27: Transportation Rate Embedded in Baseline Bundled Residential Rate Forecast (nominal \$/kWh)

Baseline Bundled Residential Electric Rate (nominal \$/kWh)											
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	\$ 0.240	\$ 0.266	\$ 0.273	\$ 0.264	\$ 0.266	\$ 0.281	\$ 0.289	\$ 0.298	\$ 0.307	\$ 0.318	\$ 0.329
SCE	\$ 0.217	\$ 0.272	\$ 0.274	\$ 0.276	\$ 0.273	\$ 0.277	\$ 0.281	\$ 0.285	\$ 0.289	\$ 0.294	\$ 0.293
SDG&E	\$ 0.302	\$ 0.300	\$ 0.328	\$ 0.338	\$ 0.340	\$ 0.355	\$ 0.371	\$ 0.388	\$ 0.405	\$ 0.424	\$ 0.443

TE Rate Embedded in Baseline Bundled Residential Electric Rate (nominal \$/kWh)											
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	\$ 0.000	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001	\$ 0.001
SCE	\$ 0.000	\$ 0.000	\$ 0.001	\$ 0.002	\$ 0.002	\$ 0.002	\$ 0.003	\$ 0.003	\$ 0.003	\$ 0.003	\$ 0.003
SDG&E	\$ 0.001	\$ 0.002	\$ 0.002	\$ 0.003	\$ 0.003	\$ 0.004	\$ 0.004	\$ 0.004	\$ 0.005	\$ 0.005	\$ 0.006

To get a rough idea of the portion of the monthly bill that corresponds to TE costs, we multiply the 2023 forecasted rates by the usage amounts that the IOUs use in their legal bill inserts¹⁴⁷ – 500 kWh per month for PG&E, SCE, and SDG&E. Through this process we see that in the near-term the portion of the bill that results from TE remains relatively low. For example, SDG&E’s 2023 estimated monthly bill portion that corresponds to TE is \$1.50/month out of a total bill of approximately \$169.00.¹⁴⁸ Using the same methodology to estimate costs further into the decade when accounting for the estimated increases in TE program spending, the bill impact from TE program spending remains low relative to the overall bill.

Caveats

While the foregoing estimates indicate a relatively low impact to customer bills, it is important to consider that IOU TE spending could, in fact, exceed our estimates in this white paper given the magnitude of investment needed to support state climate goals. However, that responsibility for IOU spending has not yet been established and the topic will be a matter of ongoing deliberation for the CPUC and the California Legislature in the coming years, with affordability being a central consideration.

¹⁴⁶ The rates in Table 27 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

¹⁴⁷ In compliance with Rule 3.2 (d) of the CPUC’s Rules of Practice and Procedure, the IOUs are to provide notice of, among other things, proposed residential rate changes addressed in a utility’s application. Bill impacts for a typical residential customer usually accompany these rate changes in a bill insert sent to customers known as the “legal bill insert.” Usage data here is that used in legal bill inserts for PG&E’s 2020 GRC Phase II, SCE’s 2021 GRC Phase II, and SDG&E’s 2019 GRC Phase II applications.

¹⁴⁸ \$0.003/kWh x 500 kWh = \$1.50/month. Rates are at class level i.e., not broken out by Non-CARE and CARE, so the monthly bill impacts presented here are for general illustrative purposes only.

Downward Pressure on Rates from TE

One consideration when assessing the affordability of EVs in the context of greater IOU spending is the notion that IOU investments in TE may have the eventual effect of placing downward pressure on rates, therefore making it even more affordable to operate an EV, in addition to lowering rates for customers not utilizing EVs.

Although some experts believe this effect will be substantial, it is unclear if it will be a significant counteracting factor considering a potential increase in spending on infrastructure needed to support TE. However, it is worthy of careful consideration. Increased electricity sales might only place a slight downward pressure on rates, but it could be sufficient to both offset TE expenditures and cause some additional decrease in rates. This can only be confirmed through future analysis. To that end, the Energy Division's Transportation Electrification Framework notes that staff may seek to establish tracking mechanisms to evaluate what pressure on rates is occurring now or in the future, as this could help better account for not only the costs, but also for the affordability benefits of greater investment in TE.

3.6 Residential Energy Cost Calculator

Background

To better understand how different long-term planning scenarios would affect customer energy bills, consultants to the CPUC (Energy and Environmental Economics, or E3) developed a Residential Energy Cost Calculator (RECC) that estimates energy bills (electricity, natural gas, and gasoline) for a set of example households.

This chapter uses the RECC to forecast customer energy bills under a baseline rate scenario and to consider the impacts of vehicle and building electrification on customer energy bills and on electric rates. The chapter is broken into two sections. The first describes the electric, natural gas, and gasoline price forecasts used in this analysis, as well as estimates of household energy bills for a representative household. It also considers the impact of a stricter electric-sector GHG target on household energy bills for households with different levels of electrification adoption. The second section is focused on the customer cost-effectiveness of vehicle and home electrification, as well as the impact of a *High Electrification* scenario on residential electric rates.

Customer Energy Rates and Bills

Background on the Residential Energy Cost Calculator

To complement existing tools used in California's integrated resource planning (IRP) process, the RECC was developed to provide a 10-year forecast of energy bills for representative households. It enables comparison among different customers under a given system portfolio, illustrating how variations in climate zone, building type, electrification status, and other factors may affect residential energy bills. The RECC

also enables comparison among different electric sector portfolios, revealing how a change in planning targets or modeling assumptions would affect bills for a given household.

IRP modeling does not explicitly consider how the costs of new generation resources are borne by individual utilities. As a result, the RECC was not designed to produce different electric rate forecasts for each IOU. For this analysis, residential electric rate forecasts for each IOU come from modeling done by the CPUC Rates team and are not based on the RESOLVE electric system planning model used in IRP. In this analysis, the RESOLVE model is only used to consider incremental generation costs associated with a particular scenario such as a more stringent GHG target or a *High Electrification* sensitivity.

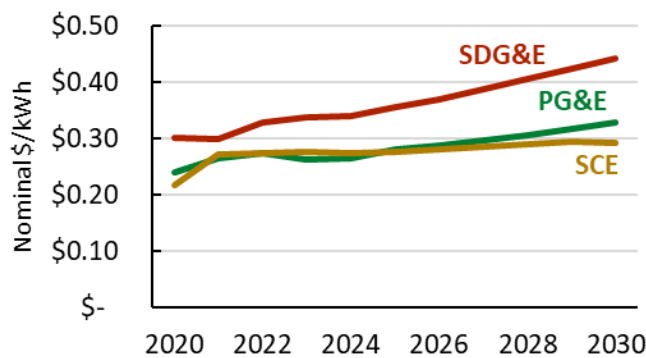
Before presenting the energy bill estimates for a representative household, the underlying forecasts for electric rates, natural gas rates, and gasoline prices are discussed below. These forecasts serve as inputs to the RECC.

Electric and Gas rates and Gasoline Prices

Electric Rates

Figure 34 shows the three large IOU bundled residential average electric rate forecasts prepared by the CPUC Rates team, as described previously.¹⁴⁹

Figure 34: IOU Bundled Residential Average Electric Rate Forecast



Natural Gas Rates

Figure 35 shows the residential gas rate forecasts developed for the three large gas IOUs: PG&E, SoCalGas, and SDG&E. Residential gas rates are generally expressed as the sum of two components: the commodity rate (the cost of natural gas itself) and the delivery (or transportation) rate, which is the regulated rate for the cost of transporting the gas to customers. For this analysis, these two components have been forecasted independently.

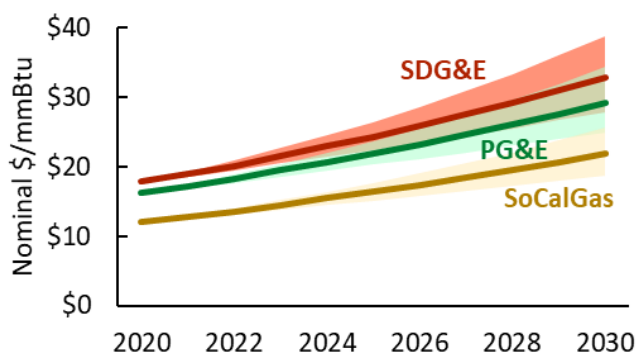
¹⁴⁹ As described in the *3.3 En Banc Bundled Residential Customer Rates Forecast*.

The commodity rate was based on gas commodity price forecasts developed by the gas IOUs and shared in the 2020 California Gas Report.¹⁵⁰ The IOUs provide these forecasts at two hubs: PG&E Citygate (PG&E) and SoCal Border (SoCalGas, SDG&E). To convert from real 2019 dollars to nominal dollars, a 2 percent annual inflation rate was assumed.

The starting point for the residential delivery rate forecast was the 2020 delivery rates for the three IOUs based on their residential tariffs. These tariffs have two tiers: a lower price for “baseline” usage and a higher price for “excess” usage. Baseline rates apply to about 70 percent of average household winter usage.¹⁵¹ A weighted average was used by applying 70 percent of the baseline rate and 30 percent of the excess rate to generate a single volumetric gas delivery rate for each IOU. Finally, the charge for public purpose programs (PPP) was added for each of the IOUs based on their PPP tariffs as of December 2020.

To consider how delivery rates may grow in the future, 11 years of historical data for California residential gas customers (2009-2019) were examined. The Energy Information Administration (EIA) provides historical residential gas rates¹⁵² and a historical average CA citygate gas price¹⁵³; the difference is assumed to be the average residential delivery rate. Taken over the period 2009-2019, the historical delivery rate shows a compound annual growth rate of 6.5 percent/year (nominal). To forecast the delivery rate for each IOU over the next 10 years, a nominal escalation rate of 6.5 percent/year was assumed for a Mid case, along with 4.5 percent/year for a Low case and 8.5 percent/year for a High case.

Figure 35: Residential Natural Gas Rate Forecast



To confirm that this is a reasonable forecast for the gas delivery rate, regulatory filings by PG&E and SoCalGas were also used for comparison. PG&E’s 2020 GRC Phase I Settlement Agreement includes 11 percent growth in the gas distribution revenue requirement from 2020 to 2022¹⁵⁴ (gas transmission costs are included in a separate filing). Combined with PG&E’s forecast of a decline in core gas sales of 1.3

¹⁵⁰ 2020 California Gas Report, Figure 2: “Natural Gas Price Chart.” Weblink can be accessed at: https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf

¹⁵¹ See e.g.:

https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/CPUC%20Rates%20Fact%20Sheet%20SCG.pdf

¹⁵² EIA Sourcekey N3010CA3, <https://www.eia.gov/dnav/ng/hist/n3010ca3a.htm>

¹⁵³ EIA Sourcekey N3050CA3, <http://www.eia.gov/dnav/ng/hist/n3050ca3a.htm>

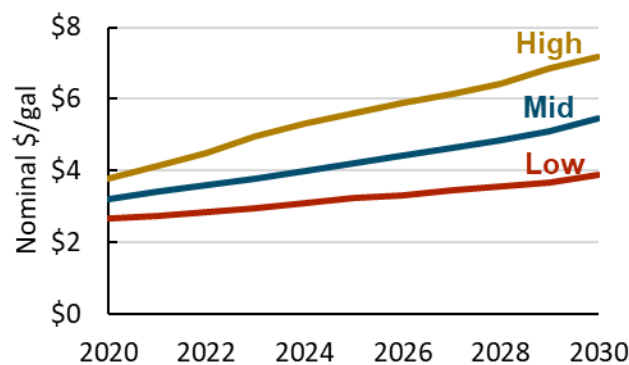
¹⁵⁴ PG&E GRC Phase 1 Settlement, Appendix C.

percent/year¹⁵⁵ and assuming a fixed revenue requirement allocation to the residential class, this results in an estimated 6.7 percent annual growth in the residential gas delivery rate (for distribution costs). The numbers are similar for SoCalGas: the 2019 GRC Phase 1 includes 19 percent revenue requirement growth from 2019 through 2022¹⁵⁶ (gas distribution, transmission, and storage); combined with residential demand falling by 1.1 percent/year¹⁵⁷, this translates to 7.1 percent annual growth in the gas delivery rate. Overall, it appears reasonable to assume the 6.5 percent historical growth in CA gas delivery rates will continue in the near-term.

It is worth noting that, while the electric rate forecast excludes the California Climate Credit, this gas rate forecast includes the Credit. Specifically, the gas rate forecast assumes that residential gas rates are indifferent to costs associated with California’s Cap-and-Trade program. Due to the much more carbon-intensive nature of natural gas as compared to California’s electric generation portfolio (which includes substantial renewable resources and is decarbonizing further every year), the impact of excluding the California Climate Credit would be larger for natural gas rates compared to electric rates.

Gasoline Prices

Figure 36: Gasoline Price Forecast



To provide a more complete picture of household energy expenditures, this analysis also includes gasoline costs for residential households. Figure 36 shows Low, Mid, and High gasoline price forecasts that were developed for this analysis. These forecasts are based on three components: a base price, an adder for California’s Cap-and-Trade program, and an adder for the state’s Low Carbon Fuel Standard (LCFS).

The base component of the gasoline price forecasts was taken from the EIA’s 2020 Annual Energy Outlook.¹⁵⁸ The base gasoline prices reflect the Pacific region forecast of gasoline prices with the “Energy Tax/Allowance Fee” component removed. For the Mid case, the Reference forecast was used. For the Low and High cases, the Low Oil Prices and High Oil Prices forecasts were used, respectively.

¹⁵⁵ 2020 California Gas Report, Table 20: “PG&E Core Throughput.”

¹⁵⁶ SoCalGas GRC Phase 1 Proposed Decision, Attachment D.

¹⁵⁷ 2020 California Gas Report, p99.

¹⁵⁸ EIA 2020 AEO, <https://www.eia.gov/outlooks/aeo/>

The Cap-and-Trade adder is based on the 2019 IEPR GHG Allowance Price forecast.¹⁵⁹ For the Mid and High cases, the “Mid” IEPR GHG Allowance Price forecast was used. For the Low case, the “Low” IEPR GHG Allowance Price forecast (which corresponds to the Cap-and-Trade price floor) was used.

For the LCFS adder, forecasts were developed by assuming \$0.10/gal in 2020 followed by a linear trend to a 2030 price. For the Mid and High cases, it was assumed that LCFS credits reach the price ceiling, corresponding to \$0.61/gal in 2030. In the Low case, it was assumed that LCFS credits reach 50 percent of the price ceiling (\$0.30/gal) in 2030, reflecting a scenario where widespread availability of biodiesel drives down credit prices.

Energy price growth rates

Table 28 shows the 10-year compound annual growth rates for residential electricity, natural gas, and gasoline prices under the Mid scenarios. Note that the same gasoline price forecast was used for each IOU service territory. Over the coming decade, electric rates are forecast to grow more slowly than natural gas rates or gasoline prices.

Table 28: 10-Year Compound Annual Growth Rates (Nominal) for Residential Energy Prices

	Electricity	Natural Gas (Mid)	Gasoline (Mid)*
PG&E	3.2%	6.0%	5.4%
SCE/SoCalGas	3.0%	6.2%	5.4%
SDG&E	3.9%	6.3%	5.4%

*Not dependent on IOU

Energy Bills for a Representative High Energy-Use Household

As shown in Figure 34 and Figure 35, electricity and natural gas rates differ by IOU, and thus customer energy bills will vary by IOU service territory. Customer bills will also vary within a given IOU territory based on factors such as CARE assistance eligibility, climate zone, building type, occupancy, vehicle miles driven, electrification status, and electric rate option.

In this section, household energy bills are presented for a single representative home. While it is common to model rate and bill impacts based on the average household, these forecasts can be misleading as California has a wide diversity of building stock as well as variation across climate zones. The analysis presented here

¹⁵⁹ 2019 IEPR Final GHG Allowance Price Scenarios, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=231777&DocumentContentId=63623>

focuses on a 1990s-vintage single-family home in a hot climate zone¹⁶⁰ as a representative household with higher-than-average energy costs.

Table 29 shows annual electricity and gas demands for this representative household, which are derived from building simulations done for the 2019 E3 report “Residential Building Electrification in California”.¹⁶¹ The energy demands of this household are greater than the average Californian household, and thus the bill projections presented here are not comparable to energy bills for average energy usage households shown earlier in this paper, such as in Figure 7 through Figure 9.

For electricity, the CPUC generally considers average residential consumption to be 6,000 kWh/year¹⁶² – the representative customer considered in this Section uses 36 percent more electricity. For gas, PG&E forecasts 38.4 MMBtu/year of natural gas usage for an average mixed-fuel residential customer in their service territory¹⁶³ – the representative customer in this Section uses 14 percent more natural gas. In choosing this household, the goal is to demonstrate the bill impacts for customers who are particularly sensitive to energy price increases. As will be explained in the subsequent chapter, many of the inland areas where summer air conditioning demands are especially high are also where affordability concerns are most pronounced, making it particularly important to understand the energy bill outlook for these areas.

Finally, note that this analysis also includes gasoline costs for a more complete picture of household energy expenditures. Household gasoline usage in this Section assumes one personal vehicle driven 13,900 miles per year¹⁶⁴ at 31 miles per gallon.¹⁶⁵

Table 29: Annual Energy Demands for a Representative Household With Above Average Energy Use in a Hot Climate Zone

Representative Household	Annual Usage
Electricity	8,150 kWh
Natural Gas	43.9 MMBtu
Gasoline	448 gal

¹⁶⁰ The CEC divides the state of California into a number of climate zones, which determine energy efficiency standards. The climate zone selected for this analysis is Climate Zone 12, which is located in the Stockton/Sacramento area. More information here: <https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/climate-zone-tool-maps-and>

¹⁶¹ E3, “Residential Building Electrification in California” (2019). https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

¹⁶² This is based on the usage level cited in legal bill inserts for PG&E’s 2020 GRC Phase II, SCE’s 2021 GRC Phase II, and SDG&E’s 2019 GRC Phase II applications

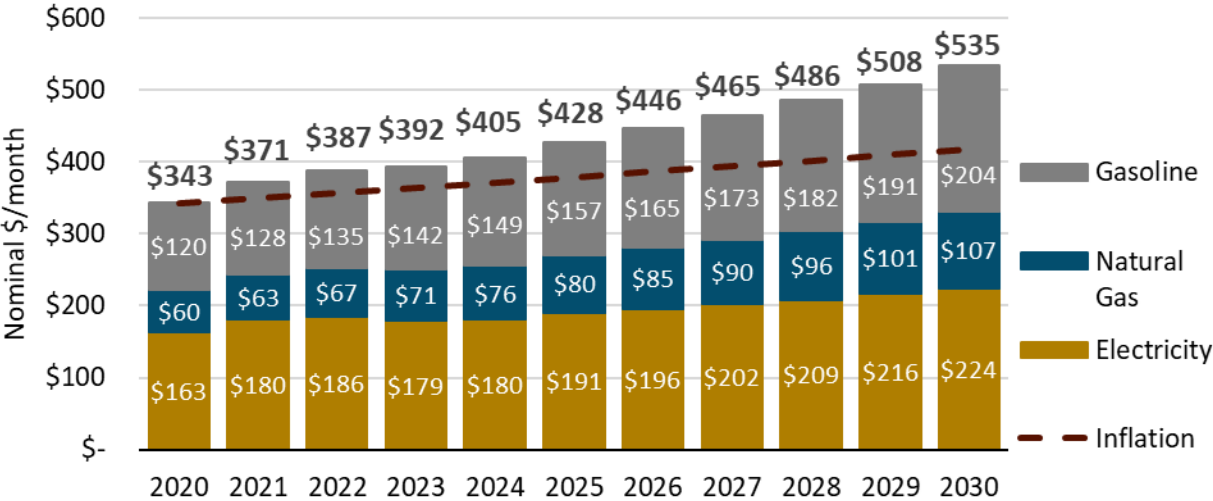
¹⁶³ PG&E Average Residential Gas Rate and Bill (January 2021). <https://www.pge.com/tariffs/Residential.pdf>

¹⁶⁴ California Air Resources Board (2020). <https://arb.ca.gov/emfac/>

¹⁶⁵ 2020, midsize sedan. ICCT, “Update of electric vehicle costs in the United State through 2030” (2019). https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf

Energy costs were modeled for this representative household assuming PG&E natural gas and electric rates. Appendix A also presents analogous results for customers with the same household energy usage assuming SCE/SoCalGas and SDG&E electricity and natural gas rates. Although the specific climate zone used in this analysis does not explicitly describe customers in SCE/SoCalGas or SDG&E service territories, these energy demands are largely reflective of California’s inland climate zones. In Appendix A, these same energy demands are used in conjunction with the SCE/SoCalGas and SDG&E electric and natural gas rates to illustrate the impact of different IOU rates on energy bills.

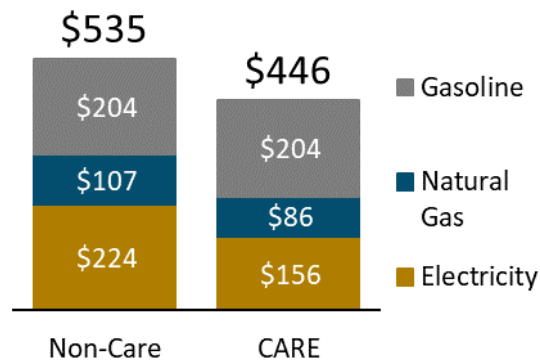
Figure 37: Average Monthly Energy Costs from 2020-2030 for Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E rates



With these assumptions established, it is possible to estimate how energy bills for this representative customer will change over time. Using the Mid case forecasts for natural gas and gasoline, and assuming simple volumetric rates for both electricity and natural gas in the PG&E service territory, Figure 37 illustrates that average monthly energy bills for this household are forecast to grow steadily over the decade, outpacing 2 percent inflation. If household income grows approximately at the rate of inflation, then energy burden (*i.e.*, energy costs as a share of income) will rise over the decade. Since this customer’s energy usage is not assumed to change over time, all of the increase in costs is due to growth in electricity and natural gas rates and gasoline prices.

Figure 37 illustrates that average monthly energy bills for this household grow steadily over the decade, outpacing 2 percent inflation. If household income grows approximately at the rate of inflation, then energy burden (*i.e.*, energy costs as a share of income) will rise over the decade. Under these rate forecasts, electricity bills rise more slowly than natural gas bills or gasoline costs.

Figure 38: 2030 Average Monthly Energy Costs for Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E Rates With and Without CARE Discounts



The growth in energy costs over the decade suggests that California’s households may increasingly struggle with energy affordability. The primary existing policy to help low-income customers pay their energy bills is the CARE program. Households enrolled in CARE receive a 30-35 percent discount on their electric bill and a 20 percent discount on their natural gas bill. Figure 38 shows 2030 monthly energy bills for the representative household described above with and without CARE discounts (30 percent on electricity, 20 percent on gas). While CARE provides a significant reduction in electricity and natural gas bills, it does not reduce the substantial gasoline costs for this customer. Although subsidizing gasoline consumption would have negative emissions impacts, policies that reduce vehicle miles driven, *e.g.*, by reducing commute distances and/or supporting transit options, would reduce both household energy bills and emissions.

Electrification of vehicles and/or building appliances can also provide opportunities for California households to reduce their energy bills. Electrification is considered later in this section.

Impact of Electric-Sector GHG Target on Household Energy Bills

Senate Bill 32 (2016) requires California’s GHG emissions to reach 40 percent of 1990 levels by 2030. The California Air Resource Board (CARB) leads a Scoping Plan process, updated at least every 5 years, to determine what policies are necessary to meet the state's climate goals. As part of the 2017 Scoping Plan, CARB developed a range of electric-sector GHG targets for 2030 that could be consistent with the economywide targets. This range is currently 30-53 million metric tonnes (MMT) for the electric sector in 2030.

In the 2019-2020 IRP process, the CPUC initially developed a 2030 emissions target of 46 MMT. After receiving feedback from stakeholders, the CPUC required California’s load-serving entities to submit two portfolios: one corresponding to a 46 MMT target and one corresponding to a stricter 38 MMT target.

The analysis presented here illustrates the bill impact of pursuing a more stringent GHG target for the electric sector. For this analysis, the RESOLVE model was used to calculate the incremental costs of meeting a 2030 electric-sector GHG target of 38 MMT relative to a baseline of 46 MMT, and those costs were added to the baseline costs developed in the CRT. In lieu of developing IOU rate forecasts that are explicitly tied to a 46 MMT or 38 MMT case, this incremental cost methodology is illustrative of the additional costs of achieving the stricter GHG target.

To calculate these incremental costs, RESOLVE was used to model two scenarios in which the 2030 emissions constraint is held at 46 MMT and at 38 MMT. In the 38 MMT case, the model builds additional renewable and storage capacity, increasing renewable procurement costs while reducing fuel costs associated with gas generation. The analysis showed the net impact on the 2030 CAISO-wide generation revenue requirement to be \$1.1B on top of a baseline CAISO-wide generation revenue requirement of \$23B.

Using IOU cost allocation and sales forecasts for bundled residential customers from the Cost and Rate Tracking tool, a 2030 rate impact of +0.6-0.8 c/kWh was estimated as a result of the stricter GHG target of 38 MMT. Due to a lack of data availability, it was not possible to prepare independent rate impacts for each IOU. It is expected that this range is applicable to IOU bundled residential customers of the three electric IOUs, assuming the methodology for allocating generation costs to residential customers does not change substantially by 2030.

Figure 39: 2030 Monthly Energy Costs for a Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E rates, Comparing 46 MMT and 38 MMT Electric Sector Emissions Targets and With Different Levels of Electrification

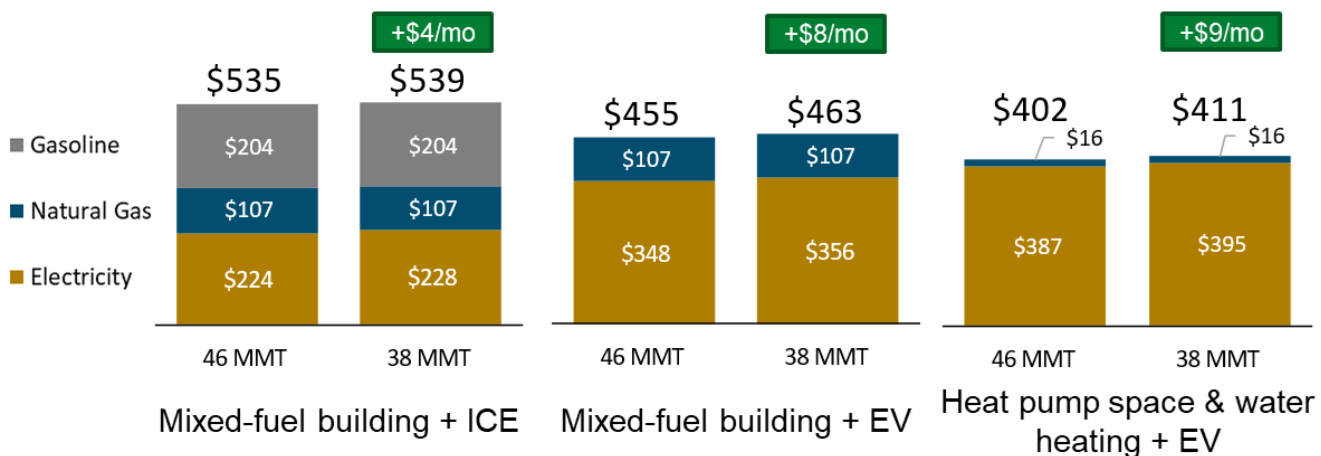


Figure 39 shows the corresponding impact on monthly energy costs for the representative household with above average energy. Two variations on this customer were also considered: a customer in the same mixed-fuel building who drives an EV, and a customer who drives an EV and has undergone “retrofit” electrification of space and water heating (but not cooking and clothes drying). Assuming a rate increase of 0.7c/kWh for the more aggressive GHG target, it is anticipated that the mixed-fuel customer with an

internal combustion engine vehicle (ICE) would see an impact of +\$4/month in their energy costs. The mixed-fuel customer with an EV would see an impact of +\$8/month and the electrified customer with an EV would see an impact of +\$9/month.

This result is one of the key conclusions from the RECC: for all three customers considered, the bill impact associated with the stricter GHG target is relatively small. Although the impact is larger for the electrified customers, their overall energy costs are considerably lower. The next section takes a closer look at how vehicle and building electrification affect customer energy costs under a range of assumptions.

Impacts of Electrification on Customer Energy Costs

This section uses the same bundled residential average electricity rate, natural gas rate, and gasoline price forecasts previously described, as well as the same household energy demands for the representative above average energy usage customer.

Energy Costs for Customers Who Adopt Vehicle and Building Electrification Technologies

Electrification of vehicle and building technologies represents a key pillar for decarbonizing California's economy. Together, vehicles and buildings represent more than half of the state's emissions. Electrification reduces emissions by enabling large gains in efficiency and leveraging the state's increasingly decarbonized electricity supply. Electrification also provides local air quality benefits by reducing the combustion of fossil fuels in homes, business, and neighborhoods. As regulators and lawmakers consider what regulations and policies will be necessary to achieve California's climate goals, it is important to evaluate the customer cost-effectiveness of different electrification technologies.

One key question is whether rising electric rates may affect electrification cost-effectiveness by 2030. This section considers operating costs associated with adopting an electric vehicle or electric building technologies over the period 2020-2030. Although the upfront capital costs of electrification are an important part of cost-effectiveness, this section is focused on operating costs (energy costs plus maintenance costs) and thus upfront capital costs are not directly included in this analysis.

The analysis presented in this section is distinct from Section 3.5. That section specifically considered the impact of transportation electrification program costs on baseline electric rates. This section considers cost-effectiveness for a customer looking to adopt an electric vehicle or electrify their home. Subsequently, the impact of a *High Electrification* case on electric rates is considered, *i.e.*, how changes in costs and sales would impact customer rates relative to a *Reference* case.

Light-Duty Vehicle Electrification

This section compares operating costs for light-duty electric vehicles (EVs) and conventional internal combustion engine vehicles (ICEs). Input data include the bundled residential electric rate and gasoline price forecasts described previously, vehicle efficiency forecasts from the International Council on Clean Transportation (ICCT)¹⁶⁶ and the assumption of 90 percent efficient EV charging infrastructure. It is assumed that customers drive 13,900 miles per year based on CARB's EMFAC database.¹⁶⁷ Finally, it is assumed that all EV owners are on a Time of Use (TOU) rate designed for EV owners: PG&E EV-2A, SCE TOU-D-Prime, or SDG&E EV-TOU-5. To model these TOU rates, it is assumed that each rate structure stays the same over the decade and that rates in all periods change proportionally with any changes in the simple volumetric rate over time. In other words, if off-peak rates on PG&E's EV-2A tariff are 66 percent of the average volumetric rate in 2020, it is assumed that they will grow by 2030 to be 66 percent of the average volumetric rate in that year.

TOU rates for EV owners enable drivers to save money by managing their charging. Managed charging profiles were developed for the three TOU rates and an unmanaged charging profile was developed corresponding to a customer who immediately charges his or her EV upon returning home from any trip. Charging profiles were developed using E3's EV Load Shape Tool, which includes household trip data from the National Household Travel Survey and optimizes charging costs while ensuring that customers have enough charge to meet their driving needs. It was found that managed charging would enable PG&E and SCE customers to charge at a 20 percent discount from the average volumetric rate and SDG&E customers could charge at a 40 percent discount due to very low overnight rates. Conversely, unmanaged charging would lead PG&E and SCE customers to pay more than the average volumetric rate, whereas SDG&E customers still see a slight discount. These estimates allocate a portion of the monthly fixed electricity fees in the SCE and SDG&E rates to EV charging.

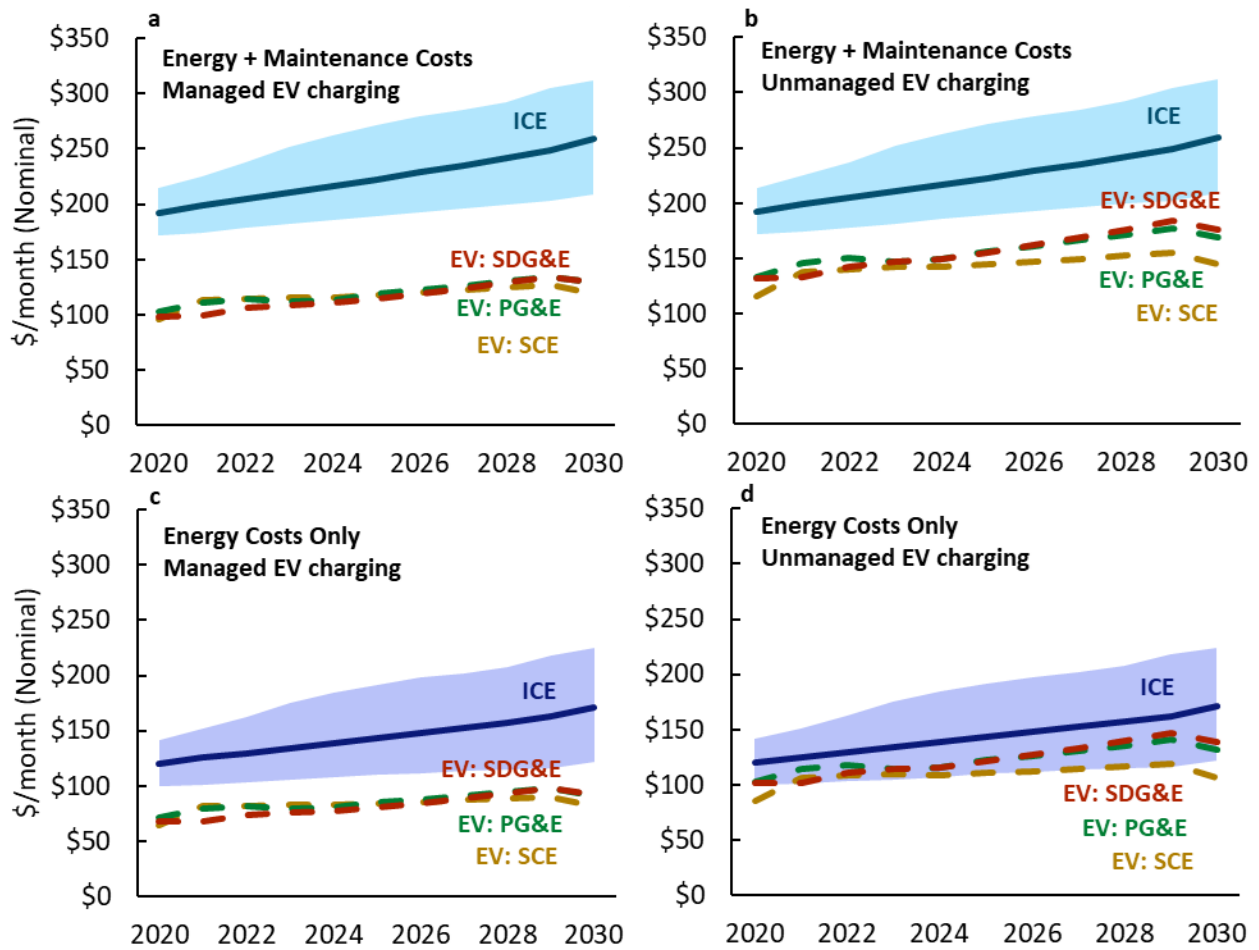
Maintenance costs are another important component of vehicle operating costs. ICCT data indicate that per-mile maintenance costs for ICEs are more than twice as high as for EVs. As these are not strictly energy costs, the analysis here is presented based on monthly operating costs (energy plus maintenance costs) as well as energy costs alone (not including maintenance costs).

Figure 40 shows four different frameworks for evaluating the potential cost savings from EVs. Under a Mid gasoline price forecast, EVs owners see cost savings throughout the decade in all four frameworks. In 2030, EV owners who manage charging are forecast to save \$130-\$140/month in operating costs (energy plus maintenance costs) as compared to an ICE owner (Figure 40a), depending on IOU. Customers who do not manage their charging see operating cost savings of \$85-\$115/month (Figure 40b). Reduced maintenance costs account for \$50/month of these savings, so energy cost savings alone are forecast to be \$80-\$90/month in 2030 for customers using managed charging (Figure 40c), and \$35-65/month for customers using unmanaged charging (Figure 40d).

¹⁶⁶ ICCT, "Update of electric vehicle costs in the United State through 2030" (2019). https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf

¹⁶⁷ California Air Resources Board (2020). <https://arb.ca.gov/emfac/>

Figure 40: Operating Costs for an ICE Under a Range of Gasoline Price Forecasts and for EVs in Three IOU Service Territories Assuming Managed and Unmanaged Charging



Under a Low gasoline price forecast (bottom of blue shaded area), EVs still show cost savings in three of the four frameworks. However, Figure 40d shows that, under the most pessimistic assumptions (Low gasoline price forecast, unmanaged charging, maintenance savings excluded), EVs may have incremental energy costs above ICEs. These graphs show that operating cost savings from light-duty vehicle electrification will vary based on many factors, but the savings are robust across a range of assumptions. Even in the scenario where low gasoline prices eliminate the energy cost savings, EV owners would still see overall savings due to lower maintenance costs.

Residential Building Electrification

This section considers the impacts of residential building electrification on household energy bills for a representative above average energy usage household in a hot climate zone. While buildings and climate vary

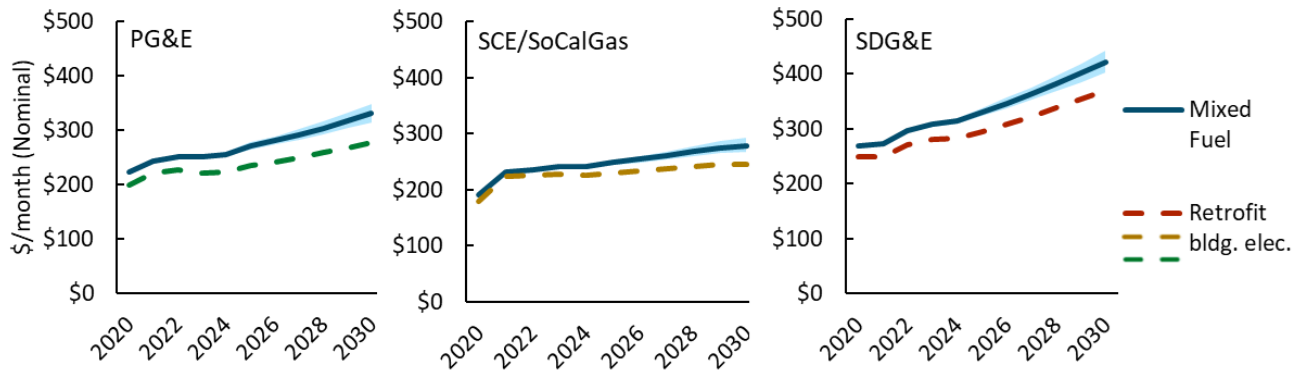
across IOU territories, the same household is considered for all three IOUs to isolate the impact of different IOU rates. This analysis considers both a 1990s-vintage single-family home that undergoes “retrofit” electrification of space and water heating, as well as a new all-electric single-family home (with distinct energy demands) that includes electric space and water heating, cooking and clothes drying. Energy costs for customers who rely on delivered fuels such as propane to meet home energy needs are not considered. The cost-effectiveness of building electrification would look considerably different for those customers.

Simple average volumetric electric rates were used for this analysis to provide directional energy cost comparisons between natural gas and electric end uses, while not considering the impact of rate design. Although utilities are transitioning to default TOU rates for residential customers, these customers may still opt for tiered rates or other TOU rate structures. As a result, it cannot be assumed that a mixed-fuel and electrified customer would be on the same rate. Overall, today’s TOU rates may support the customer cost-effectiveness of building electrification, as electrified technologies add load outside of peak air conditioning hours.

Figure 41 shows average monthly home energy bills (electricity plus natural gas) for a 1990s-vintage home considering retrofit electrification of space and water heating. Retrofit electrification provides this representative customer with substantial energy cost savings under all three IOU electric and gas rates. Notably, these cost savings are evident even under the Low natural gas price scenario. The primary source of these cost savings is equipment efficiency: high-end heat pump heating, ventilation, and air conditioning (HVAC) units and heat pump water heaters available today use between one third and one quarter of the energy of their gas counterparts.¹⁶⁸ Although gas and electricity are priced using different units, these efficiency benefits can result in substantial cost savings. Bill savings will vary based on building type and climate zone. In California’s moderate climate zones, where temperatures rarely fall below freezing and heat pumps function at high efficiencies, energy cost savings will be greater for homes with larger demands for space and water heating (*i.e.*, larger homes, homes with higher occupancy, less well-insulated homes, and regions with colder temperatures).

¹⁶⁸ E3, “Residential Building Electrification in California” (2019). https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

Figure 41: Monthly Home Energy Bills (Electricity Plus Natural Gas) for a Representative Above Average Energy Usage Home in a Hot Climate Zone Considering Retrofit Electrification of Space and Water Heating in Three IOU Service Territories

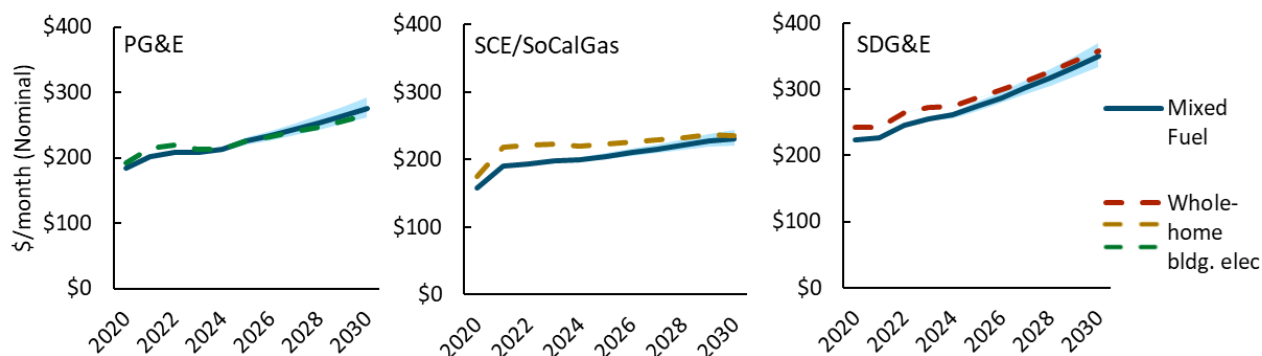


While not considered in this analysis, upfront capital costs may complicate this picture as heat pump space and water heaters may have a higher equipment and/or installation cost than corresponding gas appliances. However, heat pump HVAC units provide both space heating and air conditioning. Thus, the electrified home may save on capital costs when considering the cost of replacing an existing furnace and air conditioner with a single device.

All-electric construction of a new single-family home in a hot climate zone such as Stockton was also considered. This includes electrification of space and water heating plus cooking and clothes drying. To understand the impact of IOU rates on energy costs, customer solar was not included for this household. Figure 42 shows energy costs using rates for each IOU. The results indicate that energy costs for mixed-fuel and all-electric homes are likely to be similar over the decade and whether the all-electric home sees net bill savings or costs is sensitive to the trajectory of natural gas rates (*i.e.*, Low, Mid, or High scenario).

There are two reasons why all-electric homes may not provide the same level of energy cost savings as retrofit electrification of HVAC and water heating only. First, new homes are more energy-efficient than existing homes, reducing space heating demands and the associated energy savings from a heat pump HVAC system. Second, while heat pump HVAC units and water heaters can see 3-4x improvements in efficiency versus gas appliances, heat pump clothes dryers and induction stoves only see 2x efficiency improvement, diluting the energy cost savings from the retrofit case shown above.

Figure 42: Monthly Energy Bills (Electricity Plus Natural Gas) for a New Mixed-Fuel Home and a New All-Electric Home in a Hot Climate Zone in Three IOU Service Territories



Capital costs are not included in these calculations. However, upfront capital cost savings may favor electrification of new homes. Although electric devices may be more expensive than their gas counterparts, the all-electric home does not need an air conditioner (as this is covered by the heat pump) and the all-electric home will avoid the cost of connecting to the gas distribution system, part of which is generally paid by the homebuilder.

As the energy costs for all-electric and mixed-fuel new homes are likely to be similar throughout the decade, trends in gas and electric rates, as well as policy decisions or incentives, may ultimately determine whether all-electric customers see net bill savings or costs. The customer cost-effectiveness of all-electric new homes represents an important policy consideration for achieving emissions reductions in buildings.

Impact of Electrification on Electric Rates

The previous section describes energy costs for customers adopting electric technologies. A separate question is what the impact of electrification will be for non-adopting customers. Prior work has indicated that building electrification may lead to increases in natural gas rates for remaining gas customers as gas sales decline.^{169,170} The impact of electrification on electric rates is more complicated, as electrification will increase both electric system costs and retail electricity sales. To explore the impact of electrification on electric rates, a *High Electrification* scenario was considered that has additional costs and additional sales relative to a *Reference* case. This analysis was used to calculate a range of likely rate impacts for residential customers.

¹⁶⁹ “The Challenge of Retail Gas in California’s Low-Carbon Future.” CEC-500-2019-055-F. <https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf>

¹⁷⁰ Gridworks, “California’s Gas System in Transition.” https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf

The *Reference* scenario reflects sales assumptions from the 2019 IEPR Mid Demand case. The *Reference* scenario has 4 million EVs and plug-in hybrids on the road by 2030 (statewide) with negligible electric medium- and heavy-duty vehicles and negligible building electrification. The *High Electrification* scenario, developed in E3's CA Pathways model, sees 7 million EVs and plug-in hybrids by 2030 along with 200,000 medium- and heavy -duty vehicles and buses, plus an additional 1.1 million electrified homes and a doubling of commercial building electrification (versus *Reference*). While the *Reference* case has 15 TWh of CAISO-wide vehicle and building electrification load in 2030, the *High Electrification* scenario adds another 18 TWh of electrification load by 2030 for a total of 33 TWh.

The additional electrification load will increase electric system costs in three categories: resource procurement needed to serve load, electrification programs, and transmission and distribution (T&D) infrastructure. Incremental procurement costs were calculated by running both scenarios in the RESOLVE model. Results indicate an additional \$1.96B in 2030 procurement costs would be needed to support the additional load in the *High Electrification* case, on top of a baseline CAISO-wide generation revenue requirement of \$23B. These costs correspond to the costs of new generation resources plus the costs of transmission upgrades required to support interconnection of these resources, but not transmission or distribution costs corresponding to load increases (see below). These procurement costs likely reflect an upper bound estimate, as resource cost forecasts for solar and battery storage have fallen since the model inputs were developed in 2018.

To calculate electrification program costs, the baseline estimate of IOU program costs, which are based on utility cost filings, was used. These indicate that ~\$30 in annualized costs are required to support one incremental MWh of electrification load. For low and high estimates, \$20-\$40 per MWh of electrification load was assumed. This corresponds to an estimated \$540M in additional 2030 electrification program costs for the *High Electrification* scenario, with a range of \$360M-\$720M.

Finally, to calculate T&D infrastructure costs corresponding to increased sales, 2020 costs from the California Avoided Cost Calculator¹⁷¹ averaged across IOUs were used, along with 4 percent nominal escalation based on data from the Bureau of Labor Statistics (BLS) Producer Price Index.¹⁷² The result was \$60/kW-yr, i.e. \$60 of additional T&D annual revenue requirement for each kW of incremental peak load due to electrification. There is a range of potential peak load impacts for the *High Electrification* case. Based on load shapes from IEPR and E3 modeling, 1.9 GW of additional peak load was estimated. Based on preliminary analysis of distribution system impacts, the peak impact could likely be halved with widespread managed EV charging. Conversely, non-diversified EV charging could result in the peak impact tripling. This range of peak load impacts leads to 2030 incremental T&D costs of \$55M-\$340M, with a base estimate of \$110M.

¹⁷¹ 2020 Avoided Cost Calculator, <https://www.cpuc.ca.gov/general.aspx?id=5267>

¹⁷² BLS PPI industry data for Electric power distribution-Pacific, not seasonally adjusted. PPI Series PCU221122221122419, Jan 2015 through Nov 2020.

Table 30: Incremental Costs Associated with High Electrification Scenario

Cost component	Unitized cost	Source	2030 Mid cost (Low-High)	% of 2030 Rev Req (Low-High)
Resource procurement	NA	RESOLVE model	\$1.96B	3.8%
Electrification programs	\$30/MWh (annual rev req impact)	IOU baseline forecast	\$540M (\$360M-\$720M)	1.1% (0.7%-1.4%)
T&D infrastructure	\$60/kW-yr	CA Avoided Cost Calculator, BLS	\$110M (\$55M-\$340M)	0.2% (0.1%-0.7%)
Total	--	--	\$2.61B (\$2.38B-\$2.96B)	5.1% (4.7%-5.8%)

Table 30 shows incremental costs associated with the high electrification scenario, along with the impact on the 2030 CAISO-wide revenue requirement of \$51B (*Reference* case). The high electrification scenario adds 4.7 percent to 5.8 percent to the 2030 revenue requirement, driven primarily by additional resource procurement costs.

The proportional increase in electricity sales is larger than the increase in costs. The *High Electrification* scenario has 18 TWh of increased retail sales in 2030, corresponding to an 8.5 percent increase in sales. The result is that system average rates would fall by 0.6-0.9c/kWh. An interesting question is what level of cost increases would be necessary for rates to rise in the *High Electrification* scenario. The resource procurement costs already reflect an upper bound estimate, as described above. Thus, for the *High Electrification* scenario to result in rate increases, electrification program and T&D infrastructure costs would need to be more than double the upper bound estimates in Table 30.

The impact on bundled residential average rates was also considered using IOU-provided cost allocation data. Relative to the system-wide increases in costs and sales, bundled residential customers see a smaller (proportional) increase in revenue requirement and a larger (proportional) increase in sales. In addition, baseline residential rates are higher than system average rates, leading to larger absolute changes in rates. Taking the Mid cost estimates above, residential rates for the three IOUs would fall by 1.4-2.1c/kWh under the *High Electrification* scenario (relative to the Reference scenario based on the IEPR Mid Demand case). As explained previously, due to data limitations, it is not possible to prepare independent rate impacts for each IOU. It is expected that this range of impacts is applicable to IOU bundled residential customers of the three electric IOUs, assuming the methodology for allocation of distribution, transmission, program, and generation costs does not change substantially by 2030.

Summary of RECC Findings

Energy prices are forecasted to grow faster than inflation over the coming decade, increasing energy affordability concerns for California households. This analysis considered how the choice of electric-sector GHG target would affect energy costs and found that a stricter 2030 emissions target would lead to some bill increase for residential customers. On the other hand, it was found that building and vehicle electrification technologies represent an opportunity for customers to dramatically reduce their overall energy costs.

It was also demonstrated that operating cost savings from electrification will vary based on many factors. For light-duty vehicle electrification, operating cost savings are robust across a range of assumptions. For building electrification, operating cost savings will vary depending on IOU, natural gas rate assumptions, and end uses electrified. In addition, building type and climate zone will have an impact on electrification cost-effectiveness that has not been quantitatively considered here. It was also shown that rapid adoption of vehicle and building electrification technologies would likely have the benefit of reducing residential electric rates by 2030. While this would reduce energy costs for all California households, cost savings would be largest for customers with electric vehicles or electrified homes. The impact of electrification on natural gas rates was not considered here.

Electrification of vehicles and buildings is widely understood to be a pillar of decarbonizing the state's economy. In many cases, vehicle and/or building electrification can also provide opportunities to reduce household energy costs. However, households that cannot afford the upfront costs associated with electrification will miss out on these energy cost savings. This is an important consideration in the context of equity, since it implies that low-income families may not be able to offset the incremental costs associated with rising energy prices by reducing their natural gas, gasoline, and vehicle maintenance costs through electrification.

3.7 Affordability Framework

Affordability of utility services cannot be measured based on the magnitude of utility bills alone. Electricity and natural gas are essential services, and consumers necessarily must purchase them to maintain a healthy living standard and meaningfully participate in society. Unlike other products or services, which customers are able to forego if prices rise too high, essential utility services will continue to be consumed regardless of price. This means that for low-income households, increases in utility bills will crowd out other purchases rather than affect energy usage behavior. Instead of observing actual consumption behavior or simply comparing changes in utility bills to inflation, it is necessary to develop metrics that consider the costs of essential services in relation to the socioeconomic conditions of the households that are paying for those services.

CPUC-Developed Affordability Metrics

The CPUC has developed metrics that take into account socioeconomic conditions of representative low-income households when considering customers' ability to pay for essential services such as electricity. Specifically, in 2020 three metrics were adopted in Decision (D.) 20-07-032 (Decision) to measure the affordability of essential services: the affordability ratio (AR), socioeconomic vulnerability index (SEVI), and hours at minimum wage (HM).

Affordability Ratio

The affordability ratio (AR) metric quantifies the percentage of a representative household's income that would be used to pay for an essential utility service, after non-discretionary expenses such as housing and other essential utility service charges are deducted from the household's income. The higher an AR, the less affordable the utility service. The AR may be calculated for a single essential utility service, a combination of services, or all essential utility services combined. In the context of discussing this metric, the term "bundled AR" is used to describe the affordability of electricity, natural gas, communications, and water utility services combined.

AR may be calculated for any given income level in a given area. For example, the AR for a household at the 20th percentile income level, meaning that the household's income level is only higher than 20 percent of households in the area, would be an AR₂₀ figure. The AR for a household at the 50th percentile of income, meaning a median income household, would be an AR₅₀ figure. The AR metric is also sensitive to geographic variations in cost-of-living, which can impact the amount of income available to pay for essential utility service. AR can be calculated using publicly available data at the most geographically granular scale, census block group, or larger aggregations such as an entire utility service territory or State-wide.

Hours at Minimum Wage

The hours at minimum wage metric quantifies the hours of earned employment at the local minimum wage necessary for a household to pay for essential utility service charges. Thus, the metric allows the CPUC and stakeholders to conceive of essential utility service charges in terms of something most people can relate to – hours of labor. The minimum wage-based metric also implicitly considers the impact of essential utility service charges on lower-income customers regardless of the socioeconomic conditions of the community as a whole.

Socioeconomic Vulnerability Index

The socioeconomic vulnerability index (SEVI) metric represents the relative socioeconomic standing of census tracts, referred to as "communities," related to poverty, unemployment, educational attainment, linguistic isolation, and percentage of income spent on housing. This metric therefore considers how a rate

change may affect one community's ability to pay more than another's. The goal of the SEVI metric in this context is to highlight those communities where uniform changes in rates may have a disproportionate impact. Thus, the SEVI metric allows for an affordability assessment that is independent of the absolute value of essential utility service charges.

Advantages and Limitations of CPUC-Developed Affordability Metrics

These metrics are capable of measuring affordability outcomes at whatever level of geographic granularity is desired, so long as socioeconomic data of sufficient specificity are available and can be aligned with utility billing data. The CPUC has developed methodologies to estimate values for the three metrics described above at geographic scales smaller than utility climate zones, which is the geographic level at which the cost of an essential level of electricity usage is uniform.¹⁷³ This allows the CPUC to understand how socioeconomic factors affect the affordability of utility services, rather than just relying on the magnitude of bills as an indicator for affordability.

This is important because it allows the CPUC to measure how differences in socioeconomic factors affect the ability to pay for energy services and how much of a burden utility bills can be for households at various income levels. The degree to which these outcomes are disparate for households in different parts of the state helps the CPUC understand heterogeneity in utility affordability and quantify how much more difficult it is to pay for electricity in less affluent areas. Because the affordability ratio metric can be calculated for households at different points in the income distribution within a given area, this metric also allows for a better understanding of economic disparities within a community, in addition to differences between communities in different geographic areas.

The inclusion of non-discretionary costs in the affordability ratio metric, specifically housing costs and other utility services, provides an important piece of additional context when considering utility bills. Housing costs in particular are quite high in many parts of California, so simply considering bills in relation to household income levels (for example, by looking at a metric such as "energy burden," which expresses energy bills as a percentage of gross household income) does not account for these costs which have a significant impact on a household's ability to pay for electricity. The inclusion of housing costs allows for comparison of affordability between different parts of the state.

While the CPUC-developed affordability metrics provide benefits over other affordability metrics, they do have important limitations. Specifically, the inclusion of socioeconomic variables in the metrics means that predicting how affordability will change in future years is a more involved exercise than simply forecasting electricity rates and bills. Estimating future values of the affordability ratio requires estimates of household incomes and housing costs for specific geographic areas and for specific points on the income distribution. Forecasting SEVI values will require granular predictions of how unemployment, educational attainment,

¹⁷³ Because baseline allowances are set based on a customer's climate zone and volumetric electric rates are uniform across a utility's service territory for customers on a given tariff, the price of an "essential" level of electricity usage (defined as the baseline allowance of electricity) is determined by a customer's climate zone and electric provider. Therefore, the CPUC's affordability metrics are able to measure affordability within geographic areas where an essential level of electricity usage is of a uniform price.

poverty rates, and other socioeconomic variables will evolve over time. Predicting HM values will require some idea of how local minimum wage laws will change over time. The CPUC has not established how these forecasts will be produced for forward-looking affordability assessments. This work is part of the scope of the second phase of the Affordability OIR [R.18-07-006], which is currently underway.

Current State of Utility Affordability in California

The CPUC is able to use these metrics to understand the *current* state of affordability in California. CPUC staff recently issued the first annual Affordability Report, which provides estimates of the metrics based on 2019 data, which is the most recent data available for many of the metric components. Because the results in this report are based on 2019 data, they do not account for the impacts of the COVID-19 pandemic. The economic disparities presented in the report reflect conditions that existed before the pandemic, and those disparities have likely worsened since the beginning of 2020. A recent Center on Budget and Policy Priorities analysis of the Census Bureau’s Household Pulse Survey¹⁷⁴ found that, during the period December 9th through the 21st, 2020, 14 percent of all adults in the country reported that their household sometimes or often did not have enough to eat in the prior seven days, compared to 3.4 percent during the entire 12 months of 2019. In California during the period November 25th through December 21st, 40 percent of adults responded that they had difficulty paying for usual household expenses.¹⁷⁵

The Affordability Report contains a number of insights into the current state of bundled utility affordability. Specifically, the metrics highlight the stark disparity in affordability concerns among low-income households across the state. The results show that there are a handful of geographic areas within the state where households on the lower end of the income distribution spend a much larger proportion of their disposable income on utility services compared to low-income households in the rest of the state. Approximately 11.2 percent of households are in areas with AR₂₀ values¹⁷⁶ of at least 35 percent, while the remaining 88.8 percent are in areas with much lower values, as can be seen in Figure 43.¹⁷⁷ A higher AR value indicates that utility services are less affordable, because it means a larger proportion of discretionary income must be devoted to paying for utility services. Thus, Figure 43 shows that a small but significant proportion of low-income households in the state (i.e., households on the left side of the distribution) pay a much higher percentage of their discretionary income for vital utility services when compared to low-income households elsewhere in the state.

¹⁷⁴ The Household Pulse Survey is a recent initiative by the Census Bureau to track the social and economic impacts of the pandemic through a quick turnaround survey, with data released every two weeks. More information here: <https://www.census.gov/data/experimental-data-products/household-pulse-survey.html>

¹⁷⁵ Center on Budget and Policy Priorities, “Tracking the COVID-19 Recession’s Effects on Food, Housing, and Employment Hardships.” January 8, 2021. <https://www.cbpp.org/sites/default/files/atoms/files/8-13-20pov.pdf>

¹⁷⁶ AR₂₀ is selected as the focal point of this assessment because households at the 20th percentile of the income distribution earn considerably less than the median household, but do not necessarily qualify for assistance programs such as CARE.

¹⁷⁷ The plot presents AR₂₀ results broken down by geographic areas called PUMAs, or Public Use Microdata Areas. These are Census Bureau-defined geographic areas that are comprised of multiple census tracts. There are 265 PUMAs in California. Depending on population density, a single PUMA may contain several less populous counties or cover just a portion of a more populous county. PUMAs are delineated by metropolitan areas and other “meaningful geographies,” yielding areas with similar socioeconomic profiles.

This is an important point to understand because it shows that there are specific geographic areas within the state where affordability concerns are most acute, and those communities are significantly worse off than the rest of the state even when differences in housing costs are accounted for. Using affordability metrics that rely on service territory- or statewide-averages, it is not possible to identify these sorts of vulnerable communities.

The analysis also demonstrates that median-income households can much more easily afford utility services than lower income households. AR values for median income households (AR₅₀ values) are fairly uniform across the state, as illustrated by Figure 44, which shows the distribution of AR values for 20th and 50th percentile income households across the state. This graph shows that AR₅₀ values are relatively low compared to AR values for 20th percentile income households (AR₂₀ values), and they are less than 10 percent for the vast majority of the state.

Figure 43: Distribution of Bundled Residential AR₂₀ Values by Percent of Households (2019)

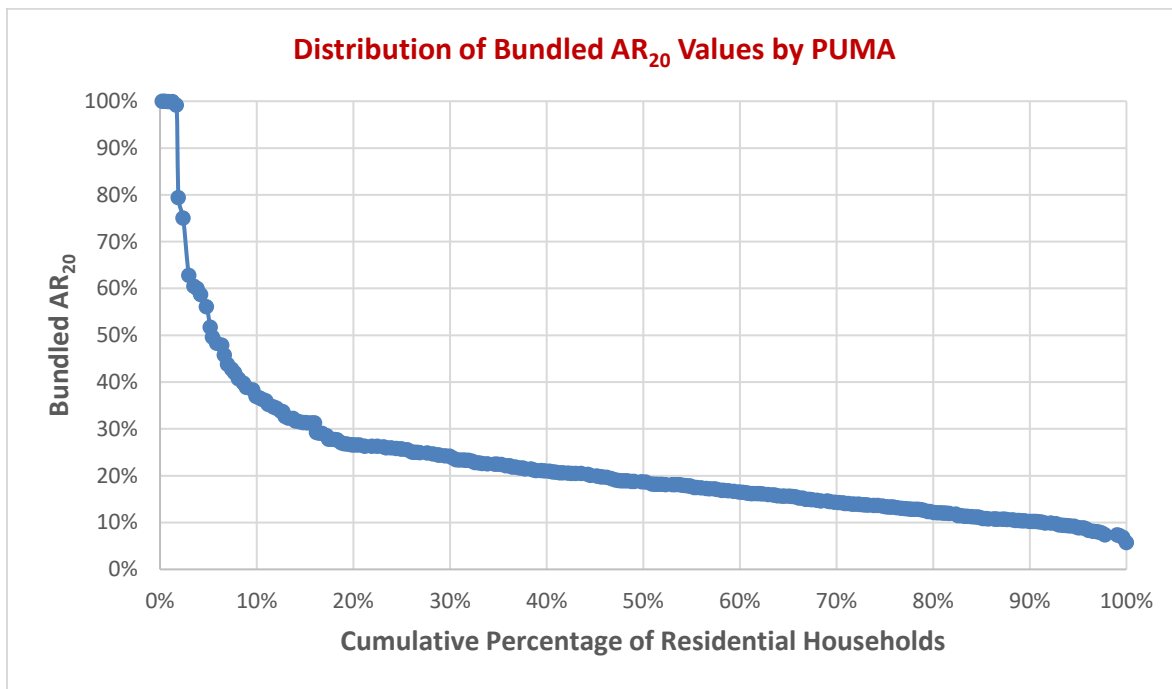
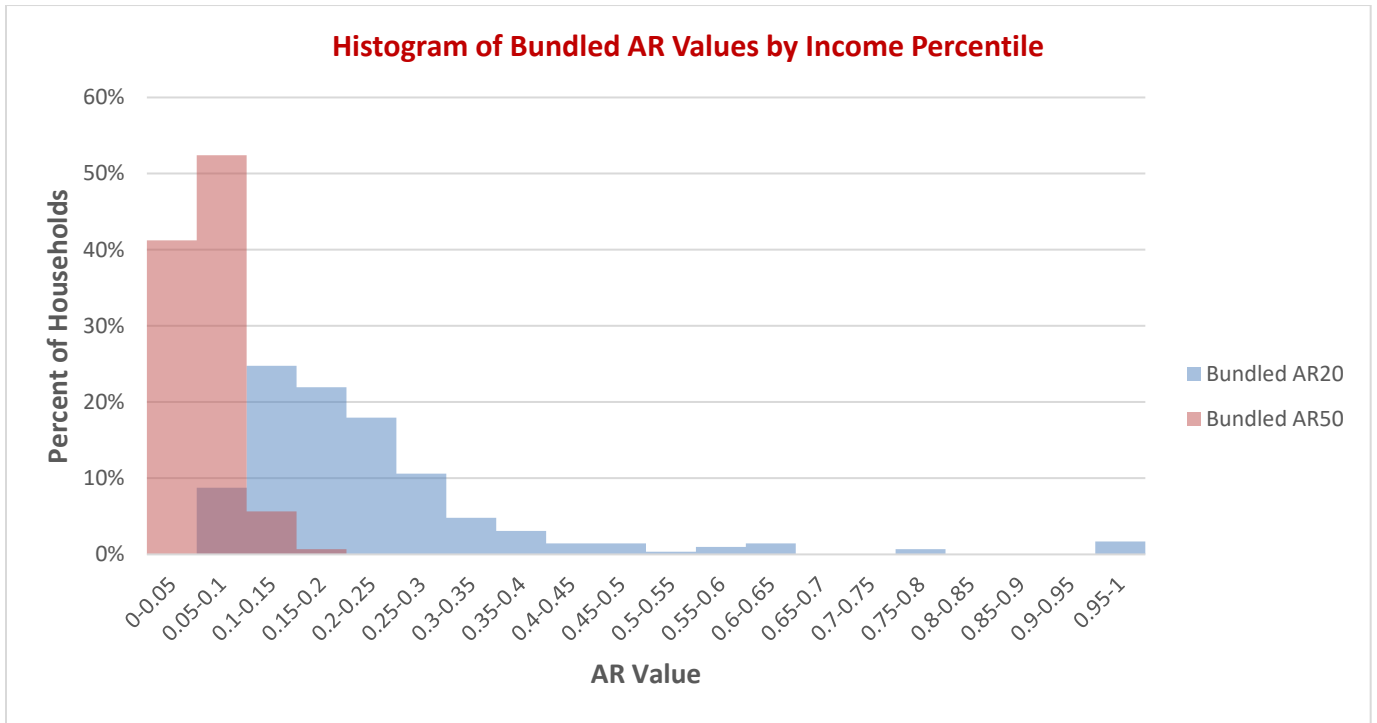
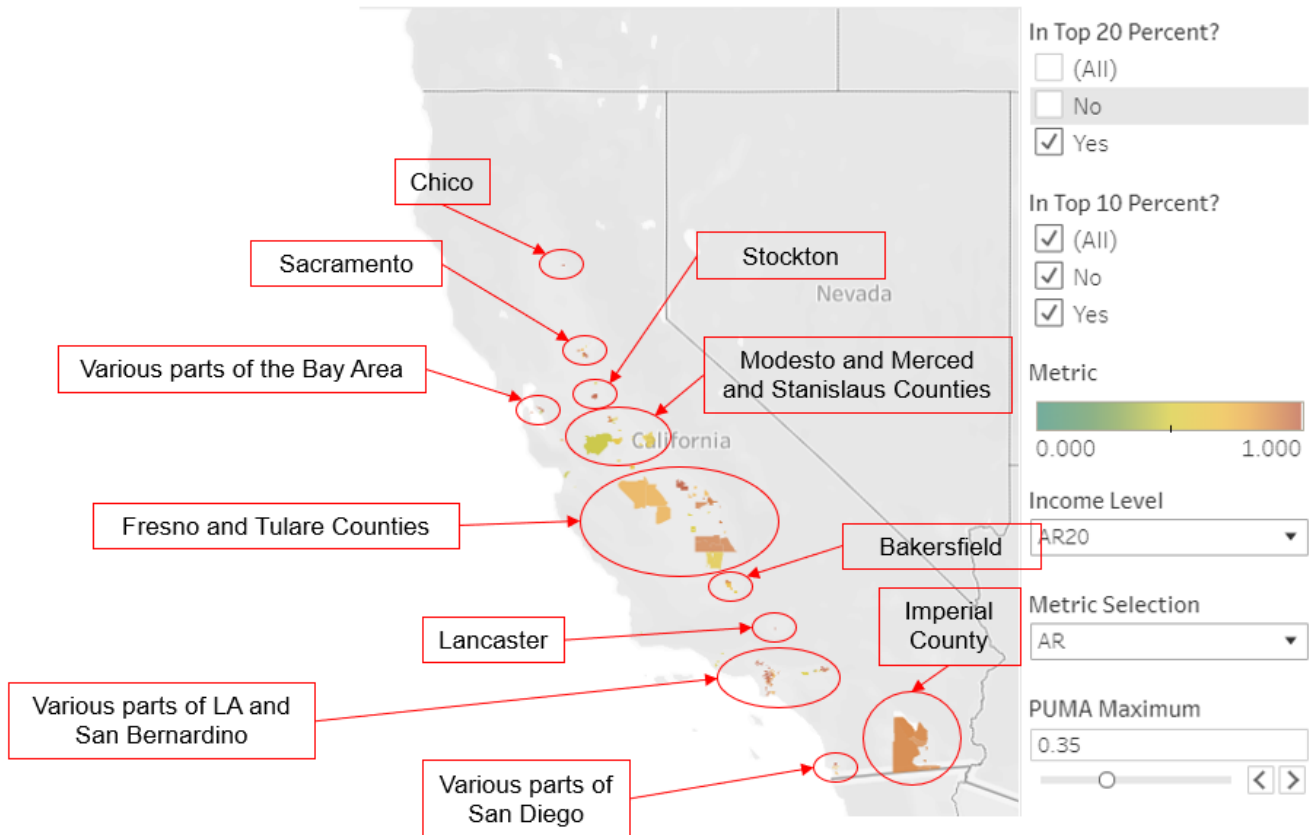


Figure 44: Histogram of Bundled AR Values by Income Percentile



The analysis also identifies the specific geographic areas where utility services are currently the least affordable for low-income households (as measured by AR₂₀) and where residents are most vulnerable to future increases in essential service charges (as measured by SEVI). In these communities, customers already face affordability challenges and are least equipped to handle further increases in utility costs. The areas with the highest values of both metrics have been identified as areas of particular concern. This includes Oakland, Stockton, Fresno, Modesto, Tulare County, Bakersfield, San Bernardino, and many parts of Los Angeles, as shown in Figure 45. These results reflect the state of affordability as of 2019, and without a geographically granular forecast of income and housing costs across the state it is difficult to definitively say how this outlook will evolve over the coming decade. However, based on the bill projections presented earlier in this report, it may be worth paying particular attention to the affordability of electricity in the San Diego area, since SDG&E bills are expected to rise more than the other electric IOUs.

Figure 45: Census Tracts with Top 20 Percent of Bundled AR₂₀ and SEVI Values



Socioeconomic Uncertainties and Future Predictions

As mentioned previously, these results are based on 2019 data, and thus reflect the pre-pandemic state of utility affordability. Given the unprecedented nature of the economic recession that resulted from the pandemic-induced shutdown of California’s economy and the persisting uncertainty around how the federal government will respond to the economic crisis, it is unclear how quickly the economy will rebound once life returns to normal.

There is particular uncertainty around how quickly employment rates and incomes will rebound for lower-income households, since recent experience from the prior economic recession showed that socioeconomically disadvantaged households did not fare as well during the ensuing economic recovery. A study of wealth changes in the aftermath of the Great Recession found that the median wealth of households which were in the top quintile of the income distribution fell to 81 percent of their 2003 level in 2011, whereas the median wealth of households in the bottom income quintile fell to 26 percent of their

2003 level in 2011, indicating that lower-income households faced a rockier road on the path to recovery.¹⁷⁸ These disparities continued to be evident even five years later: the median wealth of lower-income families in 2016 was 58 percent of the 2007 level, while the median wealth of upper-income families in 2016 was 110 percent of the 2007 level.¹⁷⁹

Perhaps even harder to predict will be the future of housing costs in California in the long-term. It is unclear to what extent remote working will be a permanent fixture in American work culture, and how that will affect where Californians choose to live, whether they need to commute, and what this will mean for service-industry jobs that previously catered to people who worked in centralized office locations. Several companies have already announced that remote work will be an option for their employees even once the pandemic is over. The economic and real estate ramifications of these changes may not be fully understood for years to come.

¹⁷⁸ Pfeffer F, Danziger S, Schoeni R. “Wealth disparities before and after the Great Recession.” *The ANNALS of the American Academy of Political and Social Science*. 2013;650(1):98–123. <https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4200506/>

¹⁷⁹ Kochhar R and Cilluffo A. “How wealth inequality has changed in the U.S. since the Great Recession, by race, ethnicity and income.” Pew Research Center. November 1, 2017. <https://www.pewresearch.org/fact-tank/2017/11/01/how-wealth-inequality-has-changed-in-the-u-s-since-the-great-recession-by-race-ethnicity-and-income/#:~:text=Consequently%2C%20the%20recession%20drove%20wealth,that%20has%20doubled%20since%201983.>

IV. UTILITY COST CUTTING PROPOSALS IN FULFILLMENT OF PU CODE SEC 913.1

The following weblink to the CPUC'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:

[IOU Proposals for Limiting Costs](#)

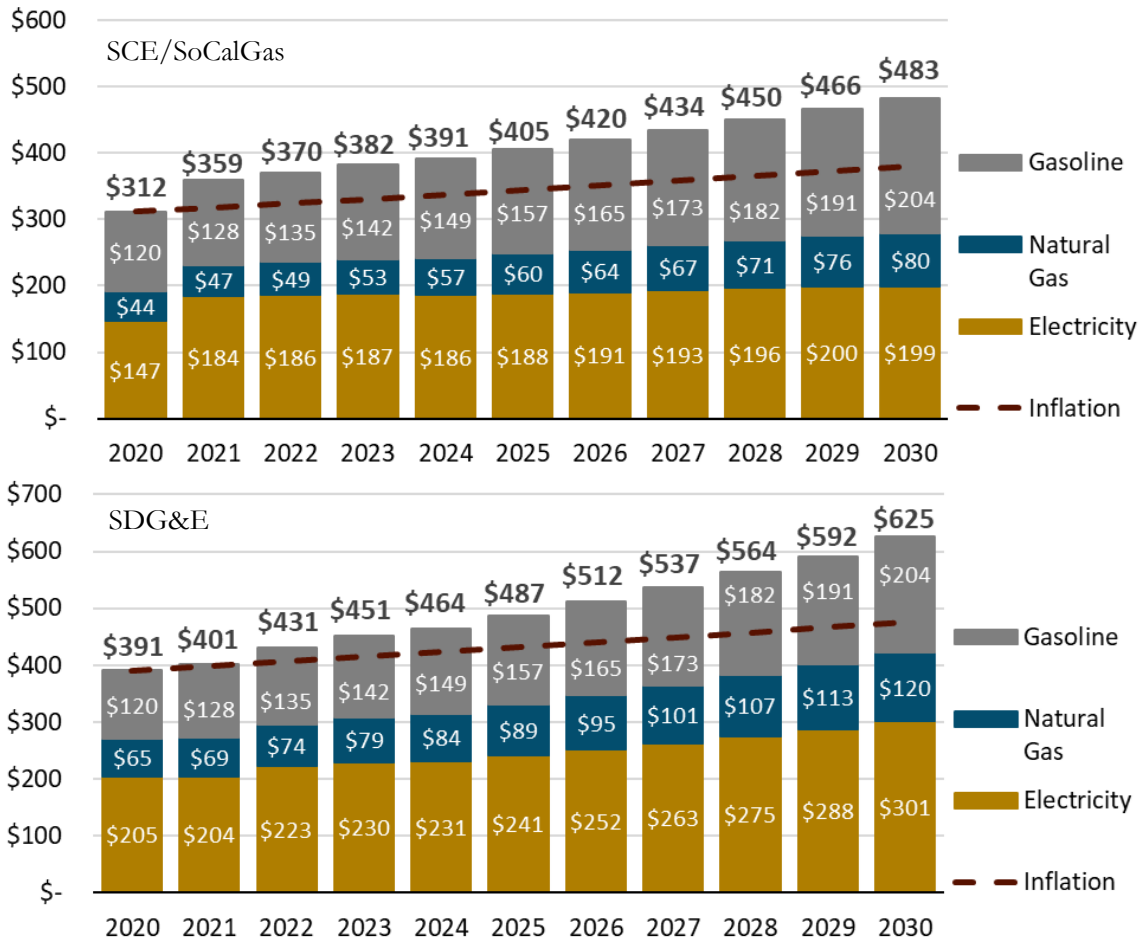
V. CONCLUSION

This white paper documents the general trajectory of costs and bundled residential rates over the next decade as the DER market expands, electrification progresses, wildfire mitigation spending and rate base investments continue to rise. This not a comprehensive evaluation and exhaustive ranking of all categories of cost, but rather an attempt to estimate long term costs alongside a distillation of affordability impacts for economically vulnerable Californians. In so doing, it warns of the need for increased prudence and equity in continued investment in the grid of the future while acknowledging that more examination is needed to understand the extent to which the load management benefits of a maturing DER marketplace might offset the potential for shifting costs. Furthermore, it raises crucial questions about the prudence of IOU proposals for capital additions and the potential for exacerbating such cost shifts and resulting bill impacts. Ultimately, the foregoing analysis is intended to engender practical thinking about strategies for utility cost containment, improved valuation of grid benefits of new technologies, and addressing affordability concerns for those customers most in need of protection.

APPENDIX A: ENERGY COSTS FOR ABOVE AVERAGE ENERGY USAGE HOME ON SCE/SOCALGAS AND SDG&E RATES

Electric rate forecasts (Figure 34) and natural gas rate forecasts (Figure 35) were developed for the three large IOUs. A representative household in a hot climate zone was also introduced (Table 29) and energy costs for this customer were shown based on PG&E rates (Figure 37). Variants of Figure 37 are presented here for customers on SCE/SoCalGas rates and SDG&E rates. Although a hot climate zone does not explicitly describe customers in SCE/SoCalGas or SDG&E service territories, these same energy demands were used across all IOUs to illustrate the impact of the different IOU rates on energy bills.

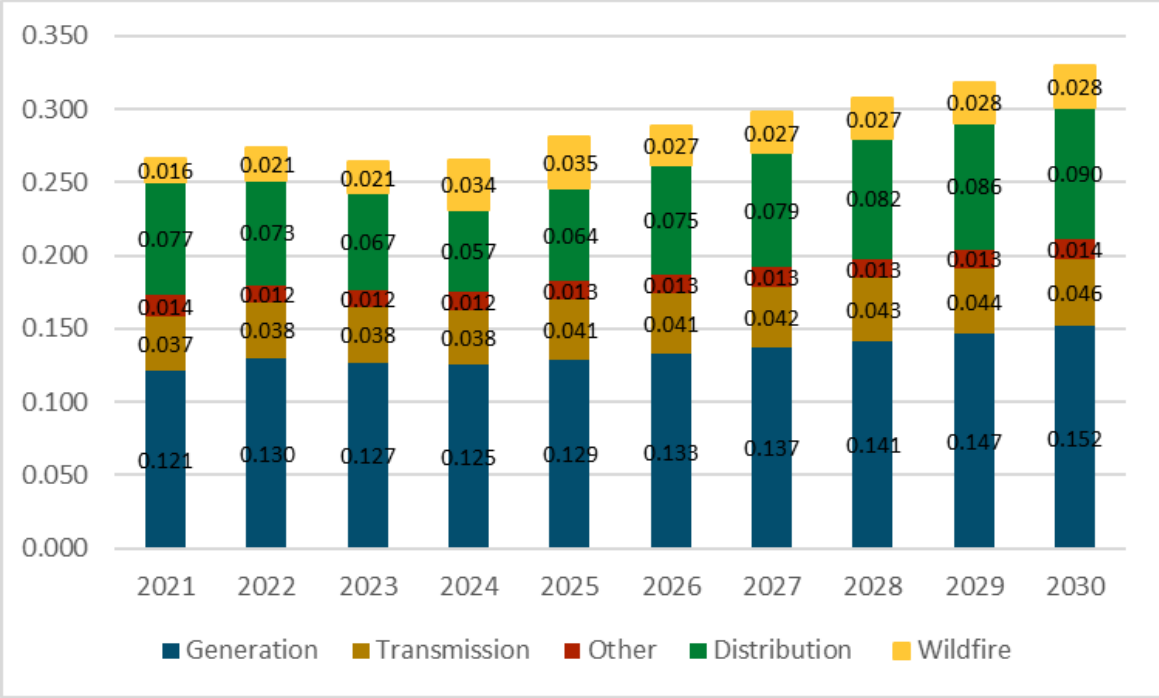
Figure 46: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SCE/SoCalGas Rates and SDG&E Rates



APPENDIX B: FORECASTED BUNDLED RESIDENTIAL RATES - EMBEDDED RATE COMPONENTS BY NOMINAL \$/KWH

Forecasted bundled residential rates in Figure 31 through Figure 33 are shown below with embedded rate component data.¹⁸⁰

Figure 47: PG&E Forecasted Bundled Residential Rates (\$ nominal/kWh), All Embedded Rate Components



¹⁸⁰ The rates in Figures Figure 47 through Figure 49 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

Figure 48: SCE Forecasted Bundled Residential Rates (\$ nominal/kWh), All Embedded Rate Components

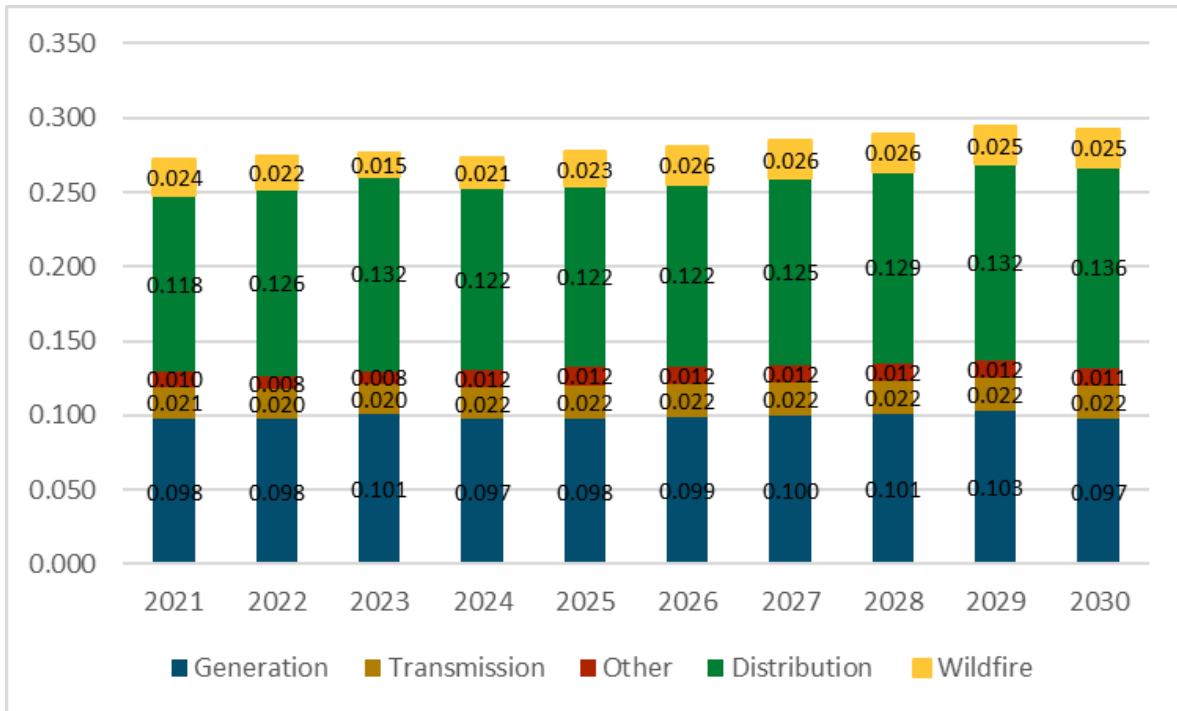
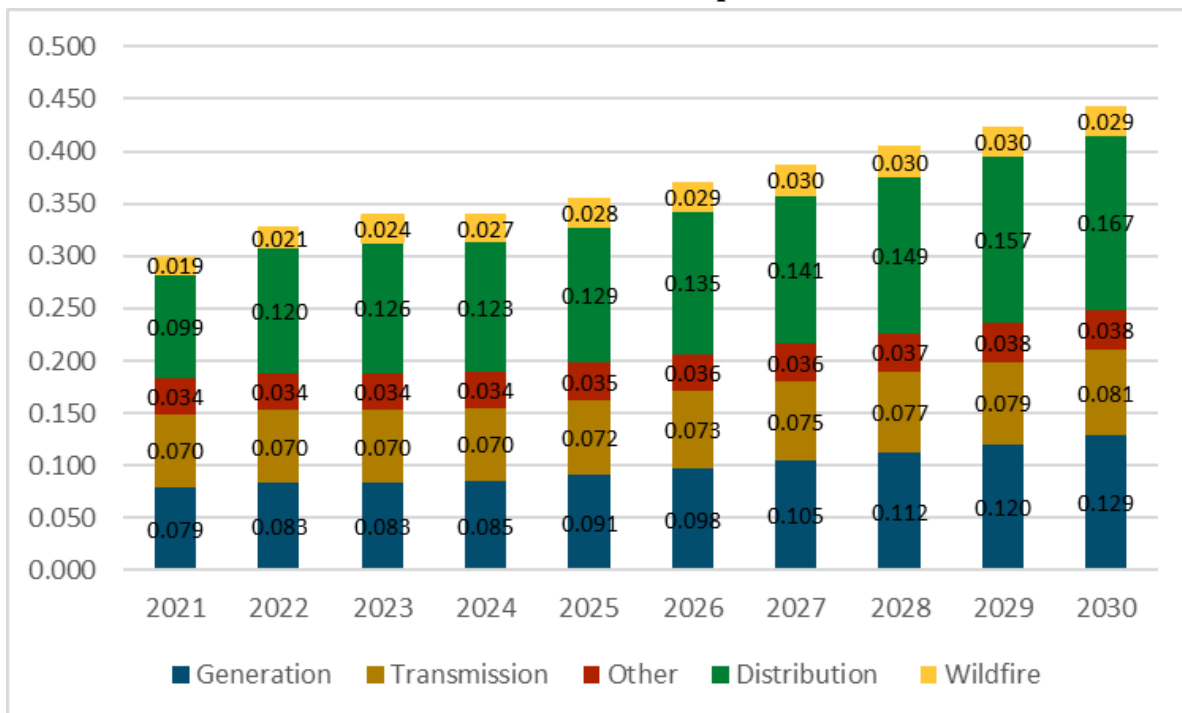


Figure 49: SDG&E Forecasted Bundled Residential Rates (\$ nominal/kWh), All Embedded Rate Components



NOTE ON ADDENDA

The following addenda supplement the draft white paper that was released prior to the February 24, 2021 CPUC En Banc hearing. Addenda 1 and 2 were prepared by CPUC staff, while Addenda 3 and 4 were submitted by external subject matter experts who do not necessarily reflect the views or opinions of the CPUC.

Addendum 1 covers historical natural gas cost trends, the outlook for future natural gas costs, and proposals to limit those costs, in fulfillment of the requirements of PU Code Section 913.1. Addendum 2 is a synopsis of the ideas presented by panelists at the En Banc hearing, as well as a summary of the public comments that were submitted following the En Banc hearing. Addendum 3 is a submission from Professor David Roland-Holst of University of California, Berkeley and covers several topics related to affordability, equity, and the framework used to evaluate those issues including prospective tools that may be needed to enhance the policymaking process. Addendum 4 is a submission from Mark LeBel and Carl Linville of the Regulatory Assistance Project (RAP), and discusses proposals for equitable cost allocation and pricing as they relate to transportation electrification and distributed energy resources.

ADDENDUM 1: NATURAL GAS COST AND RATE TRENDS

Background and Status

This natural gas addendum to the SB 695 report was prepared to complete its compliance with Public Utilities (PU) Code section 913.1. It requires the CPUC to report recommendations on how to limit cost and rate increases, consistent with the state’s energy and environmental goals, including goals to reduce emissions of greenhouse gases.

The CPUC regulates the natural gas utility services of more than 10 million customers served by Pacific Gas & Electric (PG&E), Southern California Gas (SoCalGas), San Diego Gas & Electric (SDG&E), and several smaller utilities.¹⁸¹ Critical elements of the Public Utilities Code related to gas services require that the CPUC:

1. Evaluate the reasonableness of natural gas rates and rate changes;
2. Oversee Core Transport Agent (CTA) rules¹⁸² and consumer protection matters;
3. Oversee the adoption of standards and incentives for biomethane production;
4. Oversee the implementation of utilities’ Pipeline Safety Enhancement Plans (PSEP) to pressure test or replace all intrastate transmission pipelines that do not have a record of a pressure test;¹⁸³ and
5. Determine the feasibility of minimizing or eliminating use of SoCalGas Aliso Canyon gas storage facility while still preserving energy reliability.¹⁸⁴

These mandates are reflected in ongoing activities in formal rate cases, cost allocation proceedings, several renewable natural gas efforts, and safety-oriented proceedings.

Gas customers are divided into two main categories—core and noncore customers. Residential and small commercial customers generally fall into the core category. Noncore customers include large commercial customers, including electric generators, refineries, hospitals, and manufacturers. The utilities are responsible for procuring and delivering natural gas to most core customers. Noncore customers make their own arrangements to procure the natural gas and rely on the utilities for the delivery of the natural gas. Some core customers have chosen to have a third-party CTA procure natural gas for them.

Natural gas utility costs, other than the cost of purchasing the gas commodity itself, are generally addressed in general rate case (GRC) proceedings and are composed of: capital gas transportation or transmission, distribution, storage costs; system operations, maintenance, customer service costs; administrative and general costs; and public purpose program costs. Transmission consists of the backbone and local transportation systems. The utilities’ backbone provides service on the transmission pipelines from system receipt points to customers or to the local transmission system. Local transmission transports gas from backbone pipelines and storage fields to the utilities’ distribution system. The actual cost of purchasing the natural gas is a pass-

¹⁸¹ Public Utilities Code Section 913.1(b) mandates that gas corporations with 500,000 or more retail customers in California study and report on measures the corporation recommends be undertaken to limit costs and rate increases. The large natural gas Investor-Owned Utilities (IOU) that are required by Public Utilities Code Section 913.1(b) to submit Senate Bill (SB) 695 reports are PG&E, SoCalGas, and SDG&E.

¹⁸² Core Transport Agents (CTAs) procure gas for core customers such as residential and small commercial customers as an alternative to the utility. A CTA customer does not pay the utilities’ procurement rate.

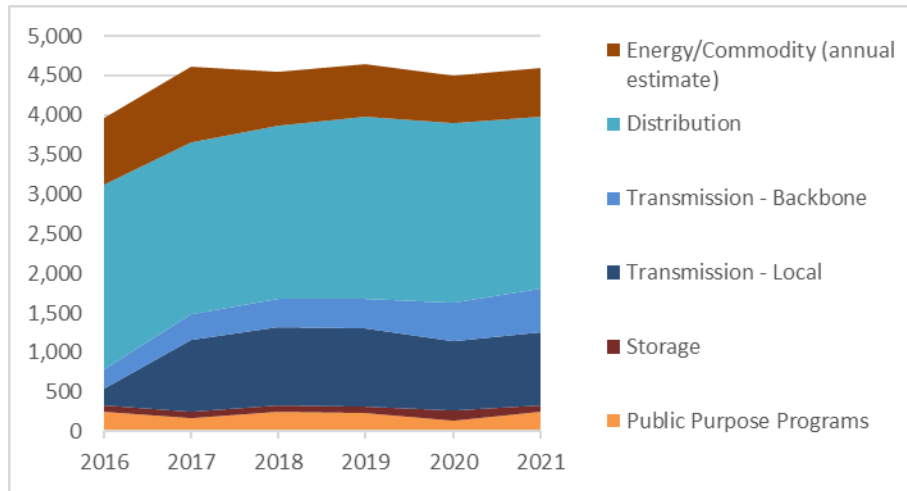
¹⁸³ Public Utilities Code Section 958: <https://codes.findlaw.com/ca/public-utilities-code/puc-sect-958.html>.

¹⁸⁴ Public Utilities Code Section 714: <https://codes.findlaw.com/ca/public-utilities-code/puc-sect-714.html>.

through to the customer, meaning the cost is not marked-up, and the costs are adjusted monthly on customer bills. See figures below for PG&E, SoCalGas and SDG&E.¹⁸⁵

PG&E Revenue Requirement by Rate Category

Figure 1: 2016–2021 PG&E January 1 Revenue Requirement by Rate Category (\$ millions)



Revenue requirement is the total annual revenue required by a public utility to recover the cost of providing service to its customers including a fair return on its investments. PG&E’s total authorized gas costs, or gas revenue requirement, has increased by approximately 16.1 percent since 2016. From 2020 to 2021, PG&E’s gas revenue requirement increased by 2.3 percent. The underlying revenue requirement components from 2020-2021 changed by the following percentages:

- Energy/Commodity increased by 3.5 percent,
- Distribution decreased by 3.8 percent,
- Backbone Transmission increased by 11.2 percent,
- Local Transmission increased by 5.7 percent,
- Storage decreased by 41.2 percent¹⁸⁶ and
- Public Purpose Programs increased by 94.6 percent.¹⁸⁷

¹⁸⁵ All data is from 2016 – 2020 IOU responses to Energy Division SB 695 Report data requests. Core procurement revenue requirement is an annual estimate and all other revenue requirements are authorized revenue requirements. For all IOUs, the core procurement revenue requirement estimate is lower in 2020 than in 2019 due to a forecasted decrease in the weighted average cost of gas in 2020.

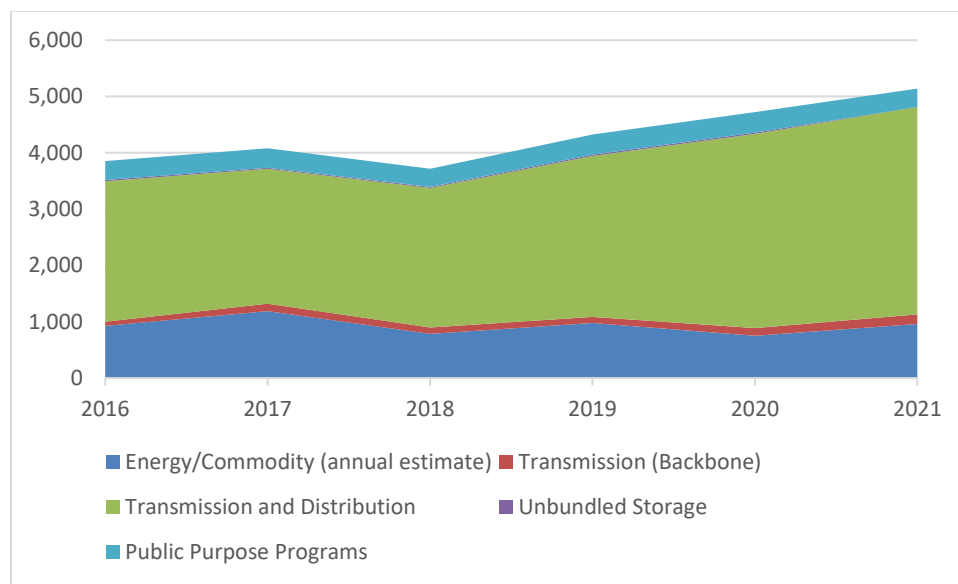
¹⁸⁶ The primary drivers of the 41.2 percent decrease in Storage costs are, as adopted in PG&E’s 2019 GT&S D.19-09-025, is a reduction of approximately \$43 million for the 2019 GT&S undercollection costs related to storage and the adoption of the Natural Gas Storage Strategy (NGSS).

¹⁸⁷ The natural gas PPP surcharge funds the following programs: Energy Efficiency (EE), Energy Savings Assistance (ESA), Statewide Marketing Education and Outreach, CARE, and public-interest R&D. In 2020, the ESA account balance included credits (accrued in 2018-

The Distribution component accounts for the largest portion of the 2021 revenue requirement.¹⁸⁸ The primary driver of the increase to the backbone transmission costs relates to targeted investments that will modernize PG&E’s gas system, such as the expansion of automatic or remotely operated shut-off valves on segments of its gas transmission pipelines located in heavily populated areas. The valves will give PG&E operators the capability to remotely shut off gas flows without having to dispatch crews. PG&E completed its PSEP scope of work in 2018, at a total cost of \$2.42 billion. PG&E continues to modernize its gas system as part of its overall transmission portfolio following the company’s risk reduction strategy.

SoCalGas Revenue Requirement by Rate Category

Figure 2: 2016–2021 SoCalGas January 1 Revenue Requirement by Rate Category (\$ millions)



Revenue requirement authorized in GRCs include the costs of operating and maintaining the utility system, capital investments in facilities and assets depreciated over its useful life, and a rate of return on invested capital for the utility. Since 2016, SoCalGas’s revenue requirement has increased by about 33 percent, with about a 9 percent increase from 2020 to 2021. Energy/Commodity are related to activities for procuring gas for core customers, and include gas commodity costs and brokerage fees, but exclude backbone transmission service (BTS) costs.¹⁸⁹ Transmission (Backbone) refers to BTS costs that are forecast to be collected as part of core commodity charges. Transmission revenue refers to base margin revenue, revenue related to regulatory account balances, other non-base margin items like PSEP, and recovery of greenhouse gas related funds. This

2019); these credits were fully refunded to customers in 2020, resulting in a lower 2020 PPP rate. The primary reason the 2021 PPP rate will increase by 94.6% is due to the fact that customers will no longer receive the ESA account balance credits they received in 2020.

¹⁸⁸ The Distribution, Backbone Transmission, Local Transmission, and Storage revenues are collected via PG&E’s transportation rate component of the gas bill.

¹⁸⁹ Backbone Transmission Service provides service on SoCalGas high-volume transmission pipelines from system receipt points to customers or to the local transmission system.

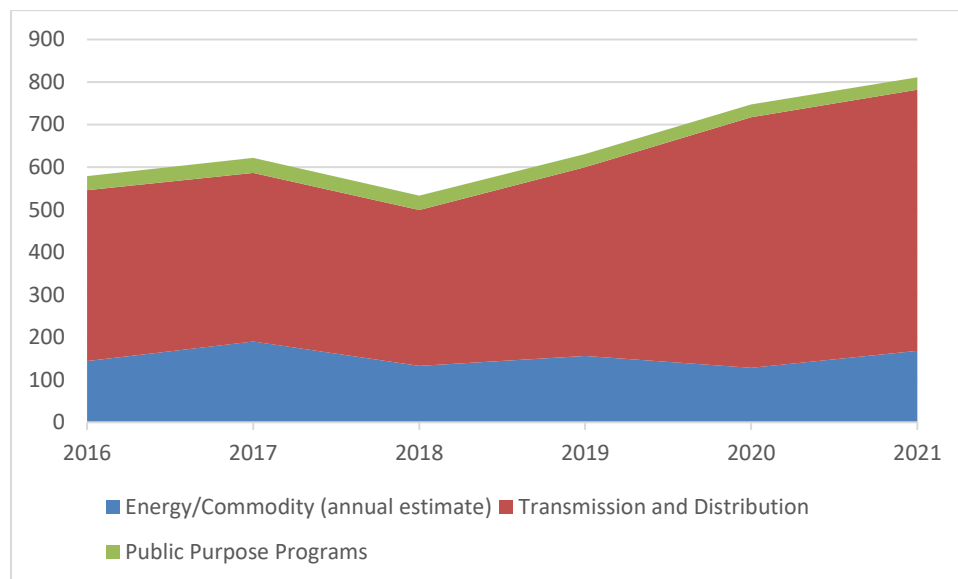
includes revenues related to the noncore portion of BTS but excludes the core portion of BTS. Revenue requirement components, from 2020 to 2021 changed by the following percentages:

- Energy/Commodity increased by 18.7 percent,
- Transmission (Backbone) increased by 3.2 percent,
- Transmission and Distribution increased by 71.7 percent, and
- Public Purpose Programs increased by 6.3 percent.

Transmission costs, which include both transmission and distribution, comprise the largest portion of the 2020-2021 revenue requirement increase. The 2021 transmission revenue requirement increases are primarily due to the implementation of SoCalGas’ 2019 GRC Phase 1 decision¹⁹⁰ attrition for 2021. A large part of the revenue requirement increases in the 2019 GRC represent costs for incremental safety-related programs and activities that are being added to the GRC for the first time because of the Risk Assessment Mitigation Phase (RAMP).¹⁹¹ In addition, there is an increase in greenhouse gas compliance cost, leak abatement costs, and amounts from decisions on the utility’s PSEP. To date, SoCalGas has spent over \$2 billion on PSEP.¹⁹²

SDG&E Revenue Requirement by Rate Category

Figure 3: 2016–2021 SDG&E January 1 Revenue Requirement by Rate Category (\$ millions)



SDG&E’s gas revenue requirement has increased by approximately 40 percent since 2016, with about a 9 percent increase from 2020 to 2021. Energy/Commodity relates to activities for procuring gas for core

¹⁹⁰ See D.19-09-051.

¹⁹¹ The CPUC developed a risk-based framework and the RAMP phase requires SDG&E and SoCalGas to identify key safety risks and to propose programs to mitigate these risks.

¹⁹² January 2021 SoCalGas PSEP Update, Appendix D: <https://www.socalgas.com/sites/default/files/SCG-SDGE%20Monthly%20PSEP%20Status%20Report%20202101.pdf>.

customers and includes gas commodity costs, brokerage fees, and BTS costs. Revenue requirement components, from 2020 to 2021, changed by the following percentages:

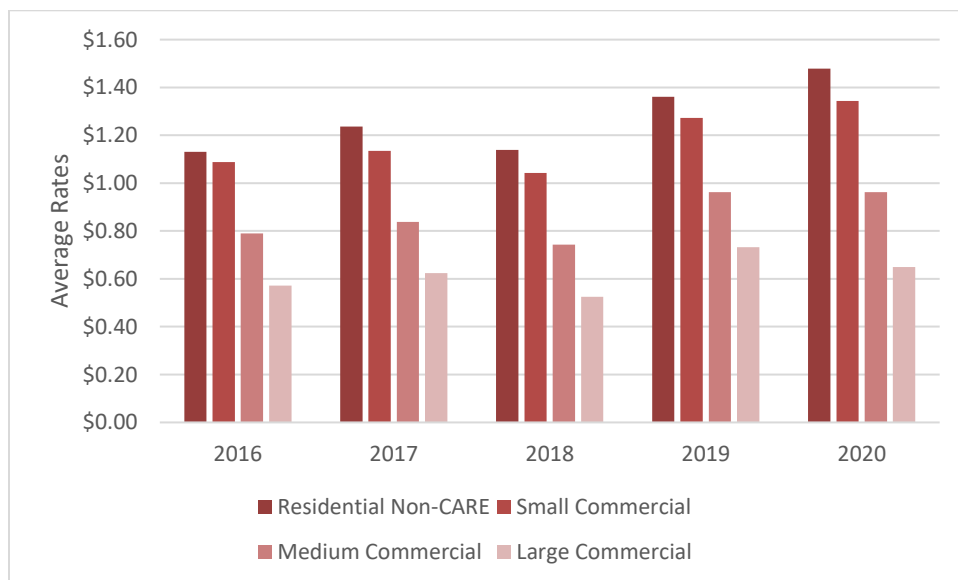
- Energy/Commodity increased by 21 percent,
- Transmission and Distribution increased by 76 percent, and
- Public Purpose Programs increased by 4 percent.

Transmission costs comprise the largest proportion of the 2020-2021 revenue requirement increase. The 2021 increase in transmission revenue requirement is primarily due to the implementation of the GRC decision¹⁹³ post-test year adjustment for 2021¹⁹⁴, partially offset by a decrease in the amount of costs recorded in balancing accounts that are being amortized in 2021. Transmission costs also include amounts from decisions addressing the utility’s overall PSEP work. SDG&E has spent more than \$603 million on PSEP to date.

Average Rates by Customer Class

A breakdown of average rates by customer class is shown for SoCalGas, SDG&E, and PG&E in Figures 4 through 6. Each class shows an upward trend during this period (2016 to 2020). Residential and small business customer classes have higher average rates than the medium and large customers with lower average rates. Residential and small business customers pay higher rates than industrial customers using larger quantities of natural gas because core customers are more expensive to serve and have greater reliability. The fixed costs of serving larger customers is recovered over larger number of therms, which result in lower rates per therm.

Figure 4: SoCalGas Average Rates, By Class, Rates in Effect January 1



¹⁹³ *Id.*

¹⁹⁴ The revenue requirement authorized in the 2019 GRC decision (D.19-09-051) is the amount of revenue the utility needs to earn in a test year (2019) and post-test years (2020 and 2021) in order to provide service to its customers.

Figure 5: SDG&E Average Rates, By Class, Rates in Effect January 1

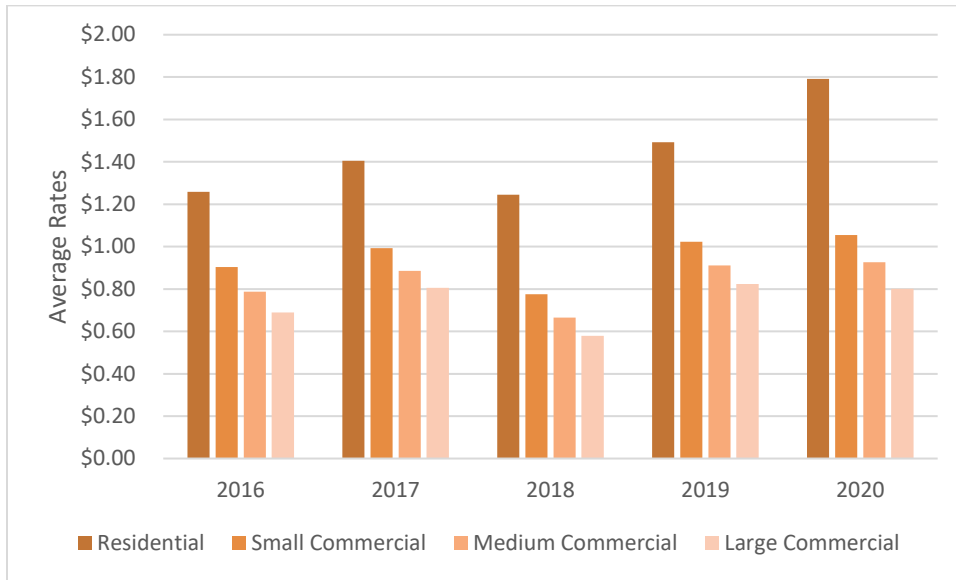
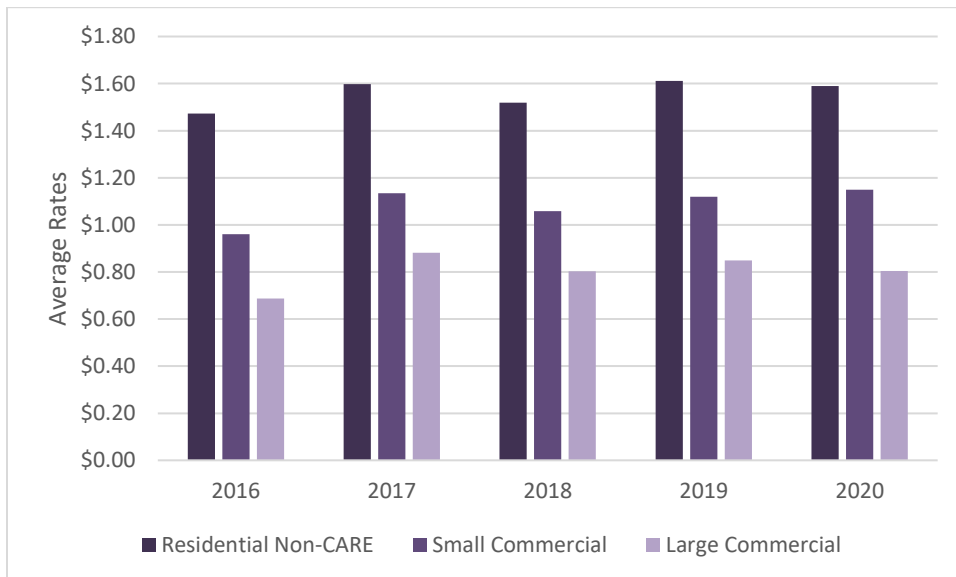


Figure 6: PG&E Average Rates, By Class, Rates in Effect January 1



Cost and Rates Containment

The CPUC has undertaken actions to limit utility cost and rate increases during the succeeding 12 months (May 1, 2021–April 30, 2022) through scrutiny of gas utility revenue requirements in GRCs and corresponding scrutiny of gas rates in cost allocation proceedings and advice letters. Gas rates can be defined as revenue requirement divided by sales. Changes to revenue requirement, determined in GRCs, and forecasted sales demand, determined in cost allocation proceedings, impact the actual rates for gas services. Similarly, changes

to forecasted demand and the allocation of the revenue requirements across customer classes impact the gas rates experienced by individual customers.

PG&E

GRC Review

In 2020, the CPUC reviewed the reasonableness of the gas costs in the settlement agreement filed in PG&E's 2020 GRC. The CPUC adopted the settlement agreement in D.20-12-005, which approved \$2.0 billion¹⁹⁵ in revenues to be collected in gas rates from PG&E customers in 2020. The settlement agreement was an agreement reached by PG&E and several parties¹⁹⁶ regarding PG&E's gas and electric revenue requirements for 2020-2022.

Residential Baseline Restructuring

In PG&E's Gas Cost Allocation Proceeding (GCAP), the CPUC mitigated PG&E's residential customer bill impacts via ratemaking actions resulting from the adoption of CPUC D.18-10-040 and D.19-10-034.

- a) D.18-10-040 modified PG&E's winter baseline structure, increasing the Tier 1 baseline levels for December and January which allows customers to use more gas at the lower Tier 1 rate, thereby mitigating residential customers' bill volatility during the winter months;
- b) D.19-10-034 increased the minimum monthly transportation bill from \$3 to \$4, thereby lowering residential customers' volumetric rates to further dampen monthly bill volatility;
- c) D.19-10-034 ordered that residential customers' Tier 1 and Tier 2 rate differentials¹⁹⁷ be narrowed over four years; doing so will further help reduce excess bill volatility.

SoCalGas and SDG&E

PSEP Review

On November 13, 2018, SoCalGas and SDG&E (the Joint Applicants) filed Application 18-11-010 for review of the reasonableness of PSEP costs for 44 pipeline projects and 39 bundled valve projects. The Joint Applicants stated that they have spent approximately \$854 million in capital expenditures and \$86.7 million in Operations and Maintenance expenses.

¹⁹⁵ D.20-12-005 Appendix B, Table 1-B, Line 1

¹⁹⁶ The Settling Parties include PG&E, the Public Advocates Office of the CPUC (Cal Advocates), The Utility Reform Network (TURN), Center for Accessible Technology (CforAT), National Diversity Coalition (NDC), Small Business Utility Advocates (SBUA), Coalition of California Utility Employees (CUE), the Office of the Safety Advocate of the California Public Utilities Commission (OSA).

¹⁹⁷ The baseline "Tier 1" allowance provides a low rate for basic gas needs. Customers pay a higher Tier 2 rate if they use more gas than the baseline allowance. The baseline allowance varies by PG&E Climate Zone.

In its August 27, 2020 decision, D.20-08-034, the CPUC adopted a Settlement Agreement resolving issues raised in A.18-11-010. Decision 20-08-034 granted the Joint Applicants a total of \$34.6 million in PSEP costs or \$4 million less than the Joint Applicants requested.

GRC Additional Years' Revenues

In April 2020, SoCalGas and SDG&E filed a joint petition to modify the decision from their 2017 general rate case to extend it two additional years (also known as “attrition years”) as directed in the January 2020 Rate Case Plan decision.¹⁹⁸ The CPUC issued a Proposed Decision on March 19, 2021, proposing revenue requirements of \$2.3 and \$2.4 billion for SDG&E and \$3.3 and \$3.4 billion for SoCalGas for 2022 and 2023, respectively. These revenue requirements are slightly less than the original utilities’ requests made in the petition. The CPUC proposed an escalation factor index to determine the amount of revenues to be collected for those two additional years, which reflects the impacts of COVID-19 pandemic on ratepayers. This reduced the utilities’ initial requested relief by \$12.9 million and \$19.5 million for SoCalGas and \$7.1 million and \$29.8 million for SDG&E, for 2022 and 2023, respectively. This revenue requirement reductions resulted in a more just and reasonable rates for customers.

Gas Costs Incentives

The Gas Cost Incentive Mechanism (GCIM) provides SoCalGas with a financial incentive to purchase and transport gas for core ratepayers at a cost that is equal to, or less than, prevailing market prices. The GCIM compares actual monthly purchased gas costs (commodity and transportation) to monthly benchmarks over the 12-month (April to March) period.

On June 15, 2020, SoCalGas submitted an application¹⁹⁹ seeking approval of a shareholder reward of \$12,806,448 for its GCIM gas procurement performance on behalf of the core customers of SoCalGas and SDG&E for the period April 1, 2019 through March 31, 2020 (also known as “Year 26”). costs (commodity and transportation) to monthly benchmarks over the 12-month (April to March) period. D.21-02-004 was issued on February 11, 2021, approving SoCalGas’ request. SoCalGas’ recorded gas costs were \$81 below the benchmark, which resulted in core ratepayer gas commodity costs that were \$69 million below prevailing market price.

TCAP Residential Baseline Restructuring

In February 2020, the CPUC adopted Triennial Cost Allocation Proceeding (TCAP) D.20-02-045, approving SoCalGas’ proposal to implement SB 711 (Hill, 2017). SB 711 required the CPUC to make efforts to minimize bill volatility for residential customers. It explicitly authorized the CPUC to do this by modifying the length of baseline seasons or defining additional baseline seasons. The CPUC adopted a two-part process to adjust

¹⁹⁸ See D.20-01-002.

¹⁹⁹ See A.19-06-009.

SoCalGas baseline calculations: 1) update the baseline allowances by reducing the residential baseline quantities so that the baseline is 70 percent of average household usage in winter and 60 percent of average household usage in summer²⁰⁰ and 2) modify the baseline seasons to divide the winter season into On-Peak (December, January, and February) and Off-Peak (November, March, and April), and retain the summer season as May through October. SoCalGas is expected to complete the billing modifications necessary to implement the modified baseline seasons beginning May 1, 2021.²⁰¹ This will result in a slight decrease in residential customers gas bills.

All Investor-Owned Utilities

Risk Spending Accountability Report (RSAR) Reviews

In December 2014, the CPUC issued D.14-12-025, which directed the investor-owned utilities under its jurisdiction to prepare annual reports comparing GRC-authorized and actual spending on risk mitigation projects and explain any discrepancies. In 2020, CPUC staff reviewed the Risk Spending Accountability Reports (RSARs) filed by the investor-owned utilities (IOUs) and identified spending patterns of concern with respect to the provision of safe and reliable gas and electric service. The RSAR reviews provide stakeholders in the general rate case process useful information regarding the IOUs' spending on major work categories for cost containment consideration in the next GRCs.

PG&E submitted its RSAR on March 30, 2020. CPUC's Energy Division Staff reviewed²⁰² and provided recommendations to include more detailed explanations of spending and unit variances that describe the decision-making process and the source and diversion of funds.

SDG&E and SoCalGas submitted their RSAR on March 31, 2020. CPUC's Energy Division Staff reviewed²⁰³, highlighting cost shifting between accounts, activities, or categories. This is the first official round of RSARs (see D.19-04-020), and parties to SDG&E and SoCalGas' GRC (D.19-09-051) served official comments to the review, which were included in the final report.

Activities and Proceedings in the Upcoming 12 Months (May 1, 2021–April 30, 2022)

OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning

²⁰⁰ SoCalGas' current previous baseline allowances have had been in effect since 2002.

²⁰¹ See SoCalGas Advice Letter 5778, approved in April 2021.

²⁰² Risk Spending Accountability Reports: <https://www.cpuc.ca.gov/General.aspx?id=6442461400>

²⁰³ *Id.*

On January 16, 2020, the CPUC opened a rulemaking²⁰⁴ to analyze long-term planning for the California natural gas system given the forecasted reductions in natural gas demand over the next 25 years. The proceeding has three tracks, with the first two tracks focused on shorter term needs to potentially adjust gas system planning and reliability standards. The third track will focus on regulatory solutions and planning strategy that the CPUC should implement to ensure that, as the demand for fossil natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, with minimal or no stranded costs.

PG&E Recovery of 2011-2014 GT&S Capital Expenditures

On July 31, 2020, PG&E filed A.20-07-020 requesting cost recovery of \$512 million for gas transmission and storage (GT&S) capital expenditures that it incurred in 2011 to 2014 above the costs that the Commission had authorized in D.11-04-031.

PG&E previously requested recovery of these GT&S capital expenditures in PG&E's 2015 GT&S rate case (A.13-12-012). Decision 16-06-056 disallowed the recovery of these capital expenditures but allowed PG&E to seek recovery of these GT&S costs in a future application, after the Commission's Safety and Enforcement Division (SED) or a third party performs an audit of the reasonableness of these costs. SED completed the audit and issued a report (Audit Report) with its findings on June 2, 2020.

Now that SED has issued the Audit Report, PG&E seeks approval to receive \$416.3 million of revenue requirement, relating to the \$512 million in 2011-2014 GT&S capital expenditures that D.16-06-056 ordered for further review and certification. To minimize the impact on customers, PG&E proposes to amortize most of the \$416.3 million revenue requirement over 36 months starting in April 2021. This proceeding is ongoing.

Aliso Canyon Order Instituting Investigation

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility while still maintaining energy and electric reliability for the region." The proceeding was divided into three phases. In Phase 1, Energy Division staff worked with stakeholders to determine the assumptions and scenarios to be used in modeling. In Phase 2, which is still ongoing, Energy Division staff performed the modeling agreed upon in Phase 1. Parties have reviewed the modeling report and some parties have requested additional modeling to be done. In Phase 3, which is also underway, a third-party consultant is modeling changes to the existing gas and electric infrastructure that would allow Aliso Canyon to be closed by 2027 or 2035.

The CPUC is also using this proceeding to determine the facility's maximum allowable gas storage inventory. SB 380 had directed the CPUC Executive Director to make that determination based on an annual report produced by the CPUC, but that code section expired on January 1, 2021, so the Commission has formalized the process in this proceeding.

²⁰⁴ See R.20-01-007.

Decisions on both Phase 2 and Phase 3 are expected in late 2021 or early 2022.

OIR to Implement Dairy Biomethane Pilots

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking²⁰⁵ to establish dairy biomethane natural gas pipeline injection demonstration projects. In 2018, the CPUC 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 CPUC. Construction of these projects should take approximately two years for interconnection to occur. Upon completion, the new dairy biomethane facilities will convert biogas from dairy digesters into renewable natural gas (RNG) for heating and transportation purposes and move California closer to its goal of reducing methane emissions by 40 percent below 2013 levels by 2030. 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 \$133 million and any deviation from those cost estimates will be reviewed as part of the CPUC's cost review work. Due to delays experienced as a result of the COVID-19 pandemic, the first of these projects was adjusted to come online in 2021 and the last of these projects will now come online in 2022.

Biomethane Procurement Considerations (SB 1440 Implementation)

In response to SB 1440 (Hueso, 2018), Phase 4 of R.13-02-008 was opened in order to explore, among other things, whether to create a biomethane procurement program. An Energy Division Staff Proposal will make recommendations on whether and to what extent it is necessary to authorize the gas utilities to procure biomethane in an effort to help California reduce methane emissions consistent with the goals outlined in SB 1383. Parties will comment on the Staff Proposal, and the Commission will ultimately decide whether to adopt its recommendations.

OIR to Aid Disadvantaged Communities in the San Joaquin Valley

On March 26, 2015, the CPUC opened a rulemaking²⁰⁶ to implement Assembly Bill (AB) 2672 (Perea, 2014). The CPUC 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 (SVJ) Disadvantaged Community under Section 783.5. Phase II of the rulemaking adopted D.18-12-015 which approved \$56 million in funding for electrification pilot projects in 11 SVJ communities and a natural gas pilot project in one community. Implementation of the pilots has begun and will be ongoing throughout 2021. As of

²⁰⁵ See R.17-06-015.

²⁰⁶ See R.15-03-010.

December 31, 2020, 320 homes have completed assessments for the pilot. A major focus of 2021 will be completing installation of the electrification and natural gas measures in those homes and all subsequent homes that receive assessments.

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

On April 16, 2018, the CPUC opened a rulemaking,²⁰⁷ R.18-04-018, to evaluate the Mobile Home Park Pilot Program (MHP Pilot Program), consider programmatic modifications, and determine if a permanent program is appropriate. Initially adopted in D.14-03-021, the MHP Pilot program converted gas and electric master metered/sub-metered mobile home parks to direct utility services. The CPUC Safety and Enforcement Division's Gas Safety and Reliability Branch (GSRB) determined the priority of MHP conversions based primarily on safety, reliability, capacity and efficiency considerations.

On April 16, 2020, the CPUC adopted D.20-04-004, finding that the pilot met its goals. Total expenditures for converting MHP gas and electric hookups in 2014-2018 were \$612 million, and 25,000 MHP spaces were converted to utility service. Apart from minor revisions, for the 2021-2030 period, D.20-04-004 retains the features of the pilot. Of the approximately 380,000 spaces in the 4,900 MHPs in California, the MHP Utility Conversion program will aim to convert 50 percent of MHP spaces by 2030 in the areas served by the large gas and electric utilities, and 100 percent of MHP spaces in the case of the smaller electric-only utilities to direct utility services. The estimated annual costs for gas and electric conversion are \$237 million for all eight utilities implementing the program. The total costs over the 2021-2030 period will be over \$2 billion, to be covered by ratepayers and reviewed in the utilities' GRCs.

SoCalGas Application to Offer a Voluntary Renewable Natural Gas Tariff

On February 2, 2019, SoCalGas and SDG&E filed a joint Application²⁰⁸ requesting authorization to offer a Voluntary Renewable Natural Gas Tariff (VRNGT) program that would allow eligible residential and non-residential customers to procure all or some of their natural gas from renewable sources. On December 17, 2020, the CPUC voted to adopt D.20-12-022 and allow SoCalGas and SDG&E to offer a modified VRNGT program that incorporates biomethane procurement targets that are in line with SB 1440.²⁰⁹ The goal of the adopted VRNGT program is to accelerate the use of biomethane, to capture methane to develop biomethane supplies, and to reduce Short-Lived Climate Pollutants (SLCPs) and other GHG emissions in California. Having a pilot program in advance of the implementation of SB 1440 may help utilities and customers gain experience in using biomethane as part of gas service, expand upon the existing biomethane market in California, and provide the CPUC with valuable information to inform future statewide biomethane procurement policies. SoCalGas and SDG&E have until June 17, 2021, to decide whether they intend to offer

²⁰⁷ See R.18-04-018.

²⁰⁸ See A.19-02-015

²⁰⁹ See D.20-12-022

a program. If they decide to do so, the CPUC will monitor the implementation and offering of the VRNGT for the next five years, to determine if it should continue.

SoCalGas, SDG&E, PG&E, and Southwest Gas Joint Application to Conduct Hydrogen Blending Demonstration Projects

On November 20, 2020, SoCalGas, SDG&E, PG&E and Southwest Gas (Joint Utilities) filed a joint application²¹⁰ regarding hydrogen-related additions or revisions to the Standard Renewable Gas Interconnection Tariff (SRGI Tariff). The Application was filed to comply with a November 21, 2019 Ruling by Commissioner Clifford Rechtschaffen, opening Phase 4 (Phase 4 Ruling) of the Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions (Rulemaking 13-02-008). In the Application, the Joint Utilities propose a definition of “renewable hydrogen”, but this issue was transferred to the proceeding, where it will be addressed. The Joint Utilities decline to offer revisions to the SRGI Tariff to allow injection of hydrogen in the Application because they have insufficient confidence that public safety, pipeline integrity, and reliability will not be compromised. In this Application, the Joint Utilities seek approval of memorandum accounts for each respective Utility. Additionally, SoCalGas and SDG&E propose a hydrogen blending demonstration program that they expect will help inform any future establishment of any appropriate hydrogen injection standards, protocols, and agreements. The cost estimate for the proposed five-year demonstration program is \$32 million. The assigned Commissioner and Administrative Law Judge are evaluating the Application.

In 2020, the Commission contracted with the University of California at Riverside to conduct a study of safe levels of injection of hydrogen into the gas distribution system and provide recommendations. The study should be completed in Fall 2021. The Commission has also approved expenditure of ratepayer funds for research on blending hydrogen in the gas distribution system as part of the California Energy Commission’s gas natural research budget (Resolution G-3571, approved November 5, 2020) and authorized SoCalGas expenditure of ratepayer funds on research on renewable hydrogen production (Resolution G-3573, approved March 18, 2021).

PG&E Application 20-08-023 to Amend Ruby Pipeline Contract

On August 28, 2020, PG&E filed Application 20-08-023 to seek approval of amendments to two contracts executed between Ruby Pipeline, LLC and PG&E. The Application seeks approval of various contract amendments which were negotiated between the parties to resolve a contract dispute resulting from PG&E’s bankruptcy and downgrading of its credit rating. A decision is expected this summer.

²¹⁰ See A.20-11-004.

SoCalGas/SDG&E Line 1600 Repairs and Replacement

In A.15-09-013, SoCalGas and SDG&E applied for a Certificate of Public Convenience and Necessity (CPCN) for the construction of a new transmission pipeline, Line 3602. The utilities also proposed to reclassify an existing transmission pipeline, Line 1600, from transmission to distribution to avoid potential customer rate impacts due to required pressure testing. In Phase One of the proceeding, the Commission evaluated the need for the proposed project pertaining to safety, reliability, resiliency, and operational flexibility and to resolve basic planning assumptions and standards that may inform the California Environmental Quality Act (CEQA)/National Environmental Policy Act (NEPA) process. On June 21, 2018, the Commission denied SDG&E's and SoCalGas' request for a CPCN for the proposed Line 3602 project.²¹¹

The Commission opened a second phase to review cost forecasts pertaining to the SoCalGas/SDG&E's Line 1600 PSEP.²¹² Under the approved plan, SoCalGas/SDG&E will replace segments of the line located in high consequence areas and hydrotest parts of the line located in non-high consequence areas. The project is estimated to cost \$677 million, with \$630 million anticipated to be capital expenditures and \$47 million estimated to be operating expenses. Phase 2 of this proceeding will enable the CPUC to provide appropriate guidance regarding the reasonableness of the cost estimates, cost containment strategies, ratemaking and accounting treatment. D.20-02-024 did not grant cost recovery in this phase; however, reasonableness review of the cost forecasts established in this phase will occur in later GRCs.

On August 12, 2020, pursuant to the decision, SoCalGas and SDG&E submitted testimony presenting forecasted costs for the SED-approved test-or-replace plan. On September 11, 2020, parties jointly filed a report following a meeting to confer on the issues. The assigned Commissioner and Administrative Law Judge will determine the next steps, including the scheduling of a prehearing conference and issuance of an amended scoping memo.

²¹¹ See D.18-08-028.

²¹² See D.20-02-024.

ADDENDUM 2: EN BANC HEARING AND COMMENT SUMMARY

Background and Overview

The En Banc hearing held on February 24, 2021 to discuss electricity costs, rates, and affordability in California produced a highly engaging discussion on a range of topics. In addition to the ideas and observations put forth by panelists on the day of the hearing, written comments were submitted by stakeholders in the following weeks. This exchange of ideas provides an important foundation for future work on controlling the growth of electric rates, while ensuring that the state's policy priorities are adequately funded.

This addendum to the white paper provides a summary of the discussion, based on the panelists' observations and stakeholders' comments.

Summary of En Banc Panelists' Presentations

The En Banc hearing consisted of three panels, as well as an introductory presentation by CPUC staff to review the key findings from the white paper. A summary of the presentations from the three panels is provided here. All points summarized here reflect the comments made by the panelists on the day of the En Banc hearing and do not include any analysis of their recommendations.

Panel 1: Can We Afford the Future?

The first panel was focused on understanding the electric rate outlook, as well as its implications for affordability, equity, and California's ambitious climate goals.

Mike Campbell (Public Advocates Office)

Mike Campbell, a manager with the Public Advocates Office, put the current residential electric rate outlook in the context of recent historical trends. Electric rates for the three big IOUs started outpacing inflation in the mid-2010s, though SCE was able to keep rate increases relatively close to inflation until fairly recently. Large wildfire expenditures are expected to push rates higher in the near future. Furthermore, electric sales have declined in recent years, meaning that the increasing revenue requirement cannot be offset by higher sales to keep volumetric rates down. This drop in sales can be attributed to the proliferation of rooftop solar. There are equity concerns associated with this trend, as the cost shift is negatively impacting customers who are unable to adopt rooftop solar and those customers tend to be in lower income and minority households. Finally, based on Public Advocates Office's comparison of electric and gasoline fuel costs, it is already cheaper to fuel a conventional internal combustion engine (ICE) vehicle than it is to charge an EV for non-CARE

customers in SDG&E's territory and that will also be the case for the other two IOUs by the end of this decade. In considering how to design EV rates, it is important to keep in mind equity considerations in addition to electrification goals.

Mad Stano (Greenlining Institute)

Mad Stano, a senior legal counsel with the Greenlining Institute, discussed the inequitable distribution of costs and benefits of California's energy policies. Electric rates are currently unaffordable, and rate reform must prioritize protecting vulnerable populations. The unaffordability of electric rates is demonstrated by the high dollar amount of arrearages that existed even before the start of the pandemic, and the recent recession has exacerbated the economic woes of already vulnerable communities. Inability to pay for electricity has dire consequences, and it is in this context that any proposed rate increase should be seen. Furthermore, Stano argued that decarbonization of California's electric grid will not occur under inequitable financing and rate schemes. Low-income households have less access to cost-saving technologies such as rooftop solar, EVs, and home electrification. With lower income households unable to electrify their homes, they will be left paying for stranded natural gas assets. Stano argued that the CPUC should stop bifurcating ratemaking for electricity and natural gas, and the CPUC must develop more protections for low-income households. Stano presented data showing that uptake of distributed energy resource (DER) technologies has been lowest in vulnerable communities, where the marginal environmental benefits would be the greatest. The conclusion is that the state needs to design DER programs so that they encourage participation in lower income communities.

Michael Colvin (Environmental Defense Fund)

Michael Colvin, a director at the Environmental Defense Fund (EDF), discussed the benefits of prioritizing medium- and heavy-duty EV adoption in vulnerable communities. California has some of the worst air quality in the country, with hot spots located in disadvantaged communities. Colvin suggests targeting policy changes (rate design; baseline usage allocation; marketing, education, and outreach; and electric vehicle infrastructure) in these same areas so that the air quality benefits of EV adoption can be maximized. Adoption will be driven by rate design, so it is important to keep electric rates low and predictable in order to keep the total cost of ownership of electric medium- and heavy-duty vehicles low. Another key component of total cost of ownership is charging infrastructure, so he recommended that multiple models for charging infrastructure deployment be considered including a role for ratepayer-funding. EVs can provide grid support services so they should be viewed as a resource.

David Rapson (University of California, Davis)

David Rapson, a professor of economics at UC Davis, presented his findings on three research questions: (1) How effective are EV subsidies? (2) Do energy prices affect EV demand? (3) How much electricity do EVs

consume? On the first question, Rapson finds that subsidies are very effective at promoting EV adoption as demonstrated by the impact of a tax credit that Georgia had previously offered. Based on his research, he also found that in California a total subsidy (state plus federal) of \$15,000 to \$25,000 was needed for each incremental EV purchased. This translates to a total cost of \$12 billion to \$18 billion in state plus federal subsidies if California is to reach its 2025 goal of 1.5 million EVs. On the second question, Rapson found that high electricity prices inhibit EV demand (a \$0.10/kWh increase in electricity prices yields a 15% decrease in EV demand) and that high gasoline prices encourage EV demand (a \$0.50/gallon increase in gasoline prices yields a 30% increase in EV demand). On the third question, Rapson presented data suggesting that EV owners were using far less electricity than had been previously estimated (2.9 kWh/day compared to the previously measured 7.2 kWh/day which had been based on dedicated EV meters from a limited sample of customers). It is possible that, as battery ranges increase, this electricity usage amount may increase in the future.

Panel 2: What Strategies for Cost Control or Reduction Do We Need to Explore?

The second panel explored options for reigning in costs so that electric rates can be kept at an affordable level.

Robert Kenney (Pacific Gas and Electric)

Robert Kenney, a vice president at Pacific Gas and Electric (PG&E), presented some initiatives that PG&E is undertaking to control costs while still delivering on its commitments to clean energy and wildfire risk reduction. The presentation included PG&E's plans to pursue operational efficiencies (work and resource planning, contract management, sale of excess renewable energy, sale of surplus properties, and headquarters redesign) that are expected to provide \$1 billion in savings per year through 2025. Kenney also presented on plans to expand the sale of licenses allowing wireless providers to attach equipment to PG&E's transmission assets, which would generate \$973 million in upfront revenue.

Carla Peterman (Southern California Edison)

Carla Peterman, a senior vice president at Southern California Edison (SCE), discussed SCE's efforts to control costs. The presentation mainly focused on SCE's plans to reduce wildfire insurance costs through customer-funded self-insurance. AB 1054 requires utilities to carry \$1 billion in wildfire insurance, which currently costs SCE about \$400 million/year. This includes multiple layers of coverage, and SCE has identified that it could save significant money by self-insuring for the highest cost coverage (the first layers of the "insurance tower"), so long as claims over a multi-year period do not exceed the premiums that would be paid to a commercial insurer. This could also result in more competitive pricing for the insurance that SCE continues to purchase through a commercial insurer.

Scott Crider (San Diego Gas & Electric)

Scott Crider, the Chief Customer Officer for San Diego Gas & Electric (SDG&E), presented on SDG&E's efforts to improve efficiency through use of technology. This includes the use of robotic process automation to automate repetitive tasks, which is expected will save the company over 700,000 hours of labor capacity by 2024. As machine learning technology progresses, more advanced tasks may be automated. Crider also discussed the use of drones to inspect assets, which should improve reliability and reduce wildfire risks while decreasing operating costs, and more advanced modeling of wildfire risks to help prioritize wildfire mitigation spending. Crider also highlighted the role of declining sales on electricity rates, particularly because of the high penetration of rooftop solar in SDG&E's territory and the relative lack of commercial and industrial load to offset the decline of residential loads. If sales in SDG&E's territory had been flat since 2012, the system average rate would be 15% lower. As a result, NEM reform is vital to keeping rates affordable.

Jennifer Dowdell (The Utility Reform Network)

Jennifer Dowdell, a senior policy expert at The Utility Reform Network (TURN), presented a set of recommendations to control utility cost growth. The recommendations were centered around three principles: (1) affordability must directly inform utility revenue requests, (2) investment in societal benefits should not create shareholder windfalls at ratepayers' detriment, and (3) diverse investment should be encouraged to reduce pressure on rates. In support of the first principle, Dowdell recommended three actions: apply the findings and methodology of the Affordability Rulemaking (R.18-07-006) to current and upcoming revenue requests; require IOUs to submit an alternative, CPI-constrained revenue proposal to reduce "anchor bias" in rate cases; and use Risk Spend Efficiency data to transparently prioritize the most cost-effective safety spending. In support of the second principle, Dowdell recommended three actions: consider CA-state asset ownership and alternative ratemaking structures for climate goal infrastructure; fund customer-side infrastructure on expense rather than capital basis; and consider general state funding of societal benefits as a less regressive alternative to ratepayer funding. In support of the third principle, Dowdell recommended two actions: favor non-utility ownership for behind-the-meter grid enhancements; and look for opportunities to leverage sources of funding other than ratepayer dollars.

Betony Jones (NextGen Policy and Inclusive Economics)

Betony Jones, an advisor to NextGen Policy and the founder and CEO of Inclusive Economics, discussed the employment and economic benefits associated with EV charging infrastructure investments and wildfire spending. Jones quantified the economic impact associated with \$10 billion of wildfire spending and estimated that it would produce on net 22,000 jobs, \$2.3 billion of labor income, and \$6.6 billion of increased economic activity. This is driven by shifting household spending, which tends to trickle out of the state, to in-state infrastructure spending. If households earning less than \$100,000 were shielded from any rate impacts

associated with the spending, the net benefits would increase to 36,000 jobs, \$3.2 billion of labor income, and \$8.8 billion of increased economic activity. This increase in net benefits is driven by the fact that lower income households' spending patterns tend to keep money in-state compared to money spent by wealthier households. Jones then discussed energy affordability more generally, pointing out that affordability is a function of the amount of energy used, the rates charged, and the amount of income available for energy spending. She suggested that rather than thinking about this as an energy affordability crisis, it might make more sense to think of this as a poverty crisis, in which case policymakers should be considering the economic impact of spending. As such, utilities should pay attention to their labor, wage, and diversity standards since the jobs they are creating also affect energy affordability.

Rick Umoff (Solar Energy Industries Association)

Rick Umoff, a senior director and counsel at the Solar Energy Industries Association (SEIA), presented strategies for using DERs to address affordability concerns. Umoff first discussed the need for NEM to evolve as a reflection of changing grid needs. According to Umoff, NEM is helping the state achieve its GHG and reliability goals, as well as driving the adoption of behind the meter storage. Going forward, it is important to expand access to distributed solar and storage so that low income households, disadvantaged communities, and renters can participate. He stressed the need for policy changes to be implemented gradually and predictably so as to attract private capital to meet the state's climate goals cost-effectively. He also highlighted the role NEM has played in jumpstarting the solar industry in California. Umoff then presented three strategies for leveraging distributed solar and storage: (1) using low-cost renewable energy to support electrification and DER deployment, (2) reducing grid costs and enhancing resilience through DERs, and (3) encouraging DER deployment to help meet the state's climate and land conservation goals.

Panel 3: Do We Need a Paradigm Shift in How California Funds Climate Change Initiatives?

The final panel considered options for fundamentally changing how the state funds climate change initiatives.

Severin Borenstein (University of California, Berkeley)

Severin Borenstein, a professor at UC Berkeley, presented his proposal for an equitable electric rate design.²¹³ He first reviewed two of the goals of electric rate design: to communicate to consumers the social marginal cost of electricity consumption (so that it incentivizes efficiency and without disincentivizing electrification) and to provide sufficient revenue to the utilities to cover their costs. An efficient rate design would price electricity at the social marginal cost, but California's rates are far higher than the social marginal cost. Marginal

²¹³ Borenstein S, Fowle M, and Sallee J. (Feb 2021). Designing Electricity Rates for An Equitable Energy Transition. *Energy Institute at Haas Working Paper*. <https://haas.berkeley.edu/wp-content/uploads/WP314.pdf>

costs make up only about 1/3 of the price of electricity in California. Fixed costs are a large component of volumetric rates. Borenstein argued that this is essentially a highly regressive tax to pay for infrastructure and public purpose programs. One alternative would be to pay for public purpose programs, climate change initiatives, wildfire spending, and infrastructure through taxpayer dollars instead of ratepayer dollars, though this might not be politically popular. Another equitable alternative would be an income-based fixed charge, where the amount charged progressively increases for higher income households.

Mark LeBel (Regulatory Assistance Project)

Mark LeBel, an associate with the Regulatory Assistance Project (RAP), discussed advanced rate design options that would allow for the efficient revenue collection without distorting price signals. LeBel started by reviewing the competing goals of electric rate design and how one could theoretically develop an efficient rate design. The problem with this process is that, at the end, there is a lump of costs beyond the marginal costs that cannot be included in the rate without distorting the efficient price signal. LeBel presented an example advanced rate that addresses the revenue shortfall issue while maintaining an efficient price signal. This example rate includes a customer charge, demand charge, a bidirectional per kWh charge on imports and exports, and symmetric time varying pricing with a critical peak price. LeBel suggested that this rate could be applied to a large set of customers who can be moved onto a more sophisticated rate fairly quickly (larger customers, customers with DERs, etc.).

LeBel also suggested that subdividing the residential rate class would give policymakers an additional tool for allocating costs. The main innovation of this advanced rate design is the bidirectional charge on imports and exports, which would recover fixed costs from customers with DERs and would be tied to the customer size. LeBel also presented an alternative solution: Ramsey pricing. In Ramsey pricing, residual costs are placed on the least elastic pricing element of the rate design, which is often the customer charge. However, this can be regressive. If the charge is tiered based on income, it gives the highest income users an incentive to defect from the grid. This approach can be difficult to implement because elasticity is not always obvious, and it also puts a lot of pressure on regulators to monitor costs.

Michael Wara (Woods Institute for the Environment at Stanford University)

Michael Wara, a director at the Woods Institute for the Environment at Stanford University, discussed ideas for reducing wildfire costs without compromising the state's goals for reducing wildfire risks and impacts. Wara started with three broad comments about the day's discussion: (1) rates are an extremely regressive way of funding programs, (2) the real affordability challenge in California is housing, and (3) the En Banc white paper reflects a best possible scenario whereas in reality there is quite a bit of risk. The key takeaway from the white paper for him was that there is no margin for error, and so the goal should be to create some headroom in case something goes wrong, making additional spending unavoidable.

With regard to wildfire spending, climate modeling suggests that wildfire risks are going to get worse over time and Wara's suggestion was to continue moving towards risk-based prioritization of spending. Furthermore, Wara suggested expanding the scope of this risk-based analysis to more than just utility activities. The state needs to look at all activities that address wildfires, including fuels reduction and home hardening. The Wildfire Safety Division may be able to take this sort of holistic look once it is a part of the California Natural Resources Agency. This analysis should include consideration of how to reduce the impacts of wildfires rather than just eliminating all possible ignition sources. Finally, Wara addressed the cost shift that is inherent in wildfire spending: the shift of costs from wildfire-prone parts of the distribution system to non-wildfire prone parts of the system. One possible solution is to consider a separate rate for customers in Tier 3 wildfire areas that better reflects the cost to serve them. Geographic segregation of rates is challenging, but worth considering. Wara closed his presentation by touching on the opportunity for DERs to provide resilience in the face of wildfire risks, and particularly the opportunity for EVs to serve as backup generation.

Anthony Kinslow II (Gemini Energy Solutions; Stanford University)

Anthony Kinslow II, CEO of Gemini Energy Solutions and a lecturer at Stanford University, presented ways the design, implementation, and evaluation of climate change initiatives can be improved to ensure more equitable outcomes. First, Kinslow discussed how long delays in program implementation and evaluation hurt the effectiveness of programs because it delays positive and negative feedback loops from being used to improve program performance. Faster feedback results in more impactful and cost-effective program delivery. Next, Kinslow discussed the importance of sufficient educational outreach to make sure communities are aware of programs that are available to them. Community Based Organizations (CBOs) play an important role in this process, and they should be compensated for their work in an equitable way. Next, Kinslow discussed how, if it is not possible to take inclusive actions at scale because of rules that prevent such actions, it is necessary to change the rules. In general, the actions should be guided by the goals of the system, which he said are captured in the CPUC's Environmental and Social Justice (ESJ) Action Plan. Finally, Kinslow talked about how problematic perceptions drive the paradigms we use to develop the goals, rules, and structures of the system that produce our programs. Racial biases need to be identified and corrected to ensure that the final outcomes are equitable.

Mark Toney (The Utility Reform Network)

Mark Toney, the Executive Director of TURN, discussed changes in the way the state thinks about how to achieve its climate change goals. In particular, Toney was focused on finding ways to end ratepayer funding of non-utility climate change initiatives (such as vehicle and building electrification). He proposed three paradigm shifts: (1) replace ratepayer subsidies with regulatory mandates, (2) develop alternative revenue streams to replace ratepayer subsidies, and (3) push agencies other than the CPUC to take the lead in designing and implementing climate change programs (because when the CPUC takes the lead, it means ratepayers will pay for the program). Toney provided examples for how to accomplish each of his paradigm shifts, including the Governor's recent mandate that all new vehicles sold by 2035 be zero emission vehicles; a proposal to

require all existing homes sold in California to be electrified; and imposing a carbon fee on ICE vehicles and using that revenue to build EV infrastructure. He also encouraged the CPUC to advocate against legislative mandates paid for by ratepayers.

Summary of Stakeholder Comments

A total of fourteen stakeholder organizations submitted comments following the En Banc hearing, as well as several individual commenters not affiliated with any organization. Individual comment filings can be found on the CPUC's En Banc website.²¹⁴ A summary of their comments is presented here, organized by topic. All points summarized here reflect the comments made by stakeholders and does not include any analysis of their recommendations.

Transportation and Building Electrification

Comments pertaining to transportation electrification (TE) and building electrification (BE) were submitted by PG&E, SCE, SDG&E, Center for Energy Efficiency and Renewable Technology (CEERT), 350 Bay Area, and the Port of Long Beach.

PG&E expressed their support for TE and highlighted a variety of mechanisms through which they've encouraged the adoption of electric vehicles (access to infrastructure, rebate programs, education and outreach, and pilot studies). They pointed out that the CEC's recent AB 2127 Assessment of charging infrastructure needs found that significant deployment of charging ports is needed to achieve the state's EV goals. In their view, as private investment picks up pace, public and customer funded support should continue to play a role and should be focused on market segments that will be missed by private third-party providers, such as multi-unit dwellings in disadvantaged communities. PG&E also agreed with the white paper's modeling of the rate impacts of TE programs: based on current programs and a simple doubling of program spending in the latter half of the decade, rate impacts will be minimal. They also agreed with the white paper's discussion of the potential for TE programs to have a downward pressure on rates by spreading fixed costs across a greater amount of kWh. They highlighted a study conducted by Synapse Energy, which found that from 2012 to 2018, EVs provided \$350M more in revenue compared to costs (programs, T&D, capacity, and generation) in PG&E's territory. That net benefit was \$600M if SCE's territory was included as well.

PG&E expressed optimism that the cost of EVs will continue to decline to the point where they have lower upfront costs than ICE vehicles, and that IOUs will play a part by continuing to fund EV rebates through low-carbon fuel standard (LCFS) revenues. PG&E indicated that they intend to propose later this year a used EV rebate funded through LCFS, with an additional rebate amount for low-income customers. They encouraged adoption of a final TE investment framework in the Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification (R.18-12-006) that allows IOUs flexibility to quickly roll out supportive programs to promote EVs.

²¹⁴ <https://www.cpuc.ca.gov/General.aspx?id=6442468423>

SCE noted that, while the white paper discusses whether or not TE will place a downward pressure on rates, it does not adequately acknowledge the important role that electrification will play in helping the state achieve its goal of carbon neutrality by 2045. As laid out in SCE's Pathway 2045 analysis, decarbonization of the electric grid combined with TE and BE is the most cost-effective way to achieve California's GHG reduction goals. This analysis also shows that electrification will reduce the average household's overall energy bills by one third by 2045. In SCE's view, this long-term perspective is important when considering near-term investments in electrification.

SDG&E appreciated the white paper's discussion of electrification and its potential to offset rate pressures but noted that the current residential rate structure is hampering electrification efforts. They said that this is because electricity prices priced above marginal costs disincentivize electrification and the associated increase in system sales. SDG&E says that although electrification is supported through technology-specific tariffs, this creates the unintended consequence of cost shift from participants to non-participants.

CEERT also appreciated the white paper's discussion of the potential for electrification to put downward pressure on rates. They advocated for higher electric sales to be coupled with increased renewable generation procurement. They were also concerned with the CPUC's recent activity in the Emergency Reliability proceeding (R.20-11-003). They contend that the CPUC should not be adding expensive natural gas generation capacity. According to CEERT, the last big near-term opportunity to invest in clean energy is procurement in the Integrated Resource Planning (IRP) proceeding (R.20-05-003). CEERT was also concerned that electrification will lead to higher natural gas rates, and that this issue should be a priority in the Gas Reliability proceeding (R.20-01-007) and the Aliso Canyon Alternatives Investigation (I.17-02-002).

350 Bay Area agreed with the white paper's analysis of electrification on household energy bills, particularly because the analysis included an outlook on all energy spending in addition to electric bills. They said that the modeling results suggest that policy solutions should focus on lowering the barriers to participation in electrification so that low and middle-income households can realize these savings.

The Port of Long Beach recommended that the white paper include a specific discussion of goods movement (medium and heavy-duty vehicles, rail, vessels at berth, and off-road vehicles) because it is an important part of the TE conversation. They said that the white paper should add a section discussing commercial rates charged to customers who operate medium- and heavy-duty vehicles and off-road vehicles, including demand charges during peak hours, capacity charges, and impacts on fleet customers, including consideration of large capital investments needed to be compliant with Executive Order N-79-20 (Governor Newsom's Executive Order calling for elimination of new internal combustion passenger vehicles by 2035). They said that the white paper should also look at actions the CPUC can take to support specific state TE requirements, including the Advanced Clean Trucks Regulation (Executive Order R-20-004) and the At Berth Regulation (approved by Office of Administrative Law on January 1, 2021, Section 2299.3, Section 931118.3, and Section 93130). They also advocated for including the impact of the rapid growth of medium- and heavy-duty EVs in future projections of electric load, as they feel use of these vehicles will grow rapidly.

Distributed Energy Resources and Net Energy Metering

Comments related to distributed energy resources (DERs) and net energy metering (NEM) were submitted by PG&E, SCE, SDG&E, CEERT, 350 Bay Area, Indivisible, California Alliance for Clean Energy (CACE), Sustainable Systems Research Foundation (SSRF), Microgrids Resources Coalition (MRC), and several unaffiliated commenters.

PG&E appreciated the white paper's section on NEM and the reference to the Lookback Study's findings: that NEM is currently not cost-effective for all customers and shifts costs from participants to non-participants. PG&E also noted the white paper's findings that the cost shift largely benefits an affluent group of customers at the expense of less affluent customers. PG&E's view is that DER programs that are not cost-effective have an impact on affordability, and that the resulting cost shift from participants to non-participants should be limited in the absence of a strong policy motivation.

SCE said that the revenue shift from NEM participants to non-participants is inequitable because participants tend to be older homeowners in high income areas whereas non-participants tend to be lower income. SCE claims that the NEM subsidy on a per participating customer basis is \$1,800, which is quite high compared to the CARE subsidy of \$375 per customer. In addition to avoiding T&D costs, NEM customers get compensated for energy at a rate of eight times what it costs to procure utility scale solar. To address these cost shift issues, SCE submitted proposals to restructure the NEM rate in Rulemaking 20-08-020.

SDG&E highlighted the role that declining sales, driven by state programs to promote energy efficiency and customer adoption of DERs, has played a key role in driving up volumetric electric rates over the last several years. SDG&E noted that, had electric sales held constant at 2012 levels, system average rates would be 15% lower and residential average rates would be 20% lower than they are currently. Sales has had such a dramatic impact on rates because fixed and sunk costs are recovered through volumetric rates. SDG&E said that NEM customers, who are generally wealthier, able to avoid the high volumetric rates through self-consumption and export credits, leaving low-to-middle income customers to shoulder the fixed and sunk costs because they cannot afford rooftop solar installations. SDG&E claimed that the cost shift is estimated to be \$3 billion per year statewide. SDG&E urged using this report to the legislature as an opportunity to highlight the role of declining sales in increasing rates and to advocate for fixed cost solutions.

CEERT acknowledged the cost-shift concerns highlighted by the white paper but encouraged the CPUC to include benefits associated with distribution investment deferral and other grid benefits into any future rates analysis. CEERT also encouraged the CPUC to update the rates analysis in the white paper to reflect any updated NEM 3.0 rate structure.

350 Bay Area recommended that the white paper include references to a pair of recent studies showing the impact of accelerating DER growth on grid costs.^{215, 216} 350 Bay Area said these studies show that interconnection of DERs on the distribution grid result in big cost savings, that DERs lead to electricity rates also decreasing over time, and that DERs enable more clean utility scale variable generation to be deployed efficiently. They also said that increase in energy efficiency and rooftop solar in California has led to the cancellation of numerous transmission projects in 2017-2018, saving \$2.6 billion in capital costs and \$10 billion in future operations, maintenance, and return on equity costs. 350 Bay Area also took issue with the use of the ratepayer impact measure (RIM) cost/benefit test to assess NEM, advocating for the use of the total resource cost (TRC) test instead.

Indivisible, CACE, and SSRF submitted similar comments expressing concern about the amount of discussion in the white paper about the cost shift associated with DERs. They urged the CPUC to promote the growth of DERs instead. They made the statement that tariffs and price signals for distributed solar and microgrids are helping to reduce costs for all ratepayers.

MRC also submitted comments expressing concern about the amount of discussion in the white paper about DERs and cost shift. MRC said that the CPUC should be more focused on controlling the other cost drivers identified in the white paper, such as increasing transmission project costs, rather than the cost shift associated with DERs. They also said that DERs and microgrids reduce the need for risky, expensive, vulnerable transmission infrastructure.

Several unaffiliated commenters also responded to the white paper and En Banc hearing by advocating for the full range of benefits of DERs to be included in any CPUC analysis of NEM. Many of these comments reflected the statements made by CEERT, 350 Bay Area, Indivisible, CACE, SSRF, and MRC.

Capital Costs, Rate Base, and Return on Equity

Comments concerning capital costs, rate base, and return on equity (ROE) were submitted by PG&E, SCE, SDG&E, the Center for Sustainable Energy (CSE), Indivisible, CACE, SSRF, and MRC.

PG&E provided background on the role that capital financing plays in the utility industry in order to provide additional context for the white paper's findings regarding rate base and ROE. PG&E said that ROE does not guarantee any level of profit, since IOUs still need to manage overall costs (capital and O&M) so that they come in under the authorized revenue requirement. Investments in unneeded assets run the risk of disallowances that reduce profit, contrary to white paper's assertion that IOUs have an incentive to increase

²¹⁵ Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report, Princeton University, Princeton, NJ, December 15, 2020. Available at: https://environmentalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

²¹⁶ Why Local Solar For All Costs Less: A New Road Map For The Lowest Cost Grid; Christopher Clack et al, 1 December, 2020. Available at: https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_ES_Final.pdf

rate base in order to earn higher profits. According to PG&E, IOU profits reflect compensation to shareholders for the time value of their money as well as for bearing risk. Higher risks necessitate higher profits, and therefore the cost of capital is high in California because of the high risk compared to elsewhere in the country. PG&E also pointed out that the revenue requirement of rate base has held steady at about 1/3 of total cost of electric service for many decades, indicating that rate base has been growing at about the same rate as other utility costs. Finally, PG&E said that the CPUC has some control over the growth in rate base through depreciation rates. Rate base growth can be slowed through higher depreciation rates, which would increase rates in the short-term but slow growth in the long-term. PG&E said that consumer advocates have historically preferred lower depreciation rates.

SCE also sought to provide additional context for the rate base growth findings in the white paper. SCE said that growth in rate base is driven by safety, reliability, and risk mitigation spending. These investments undergo vetting by the CPUC and stakeholders. From 2009 to 2019, SCE's capital spending was within 1% of GRC-authorized capital funding, which they say demonstrates that there is no systematic attempt to overspend. Further, they said that over the last several years SCE has attempted to increase net salvage rates which would offset rate base. However, they say that the CPUC has adopted lower net salvage rates than requested out of concern for near-term rates, which has shifted costs to the future. SCE also argued that an adequate ROE is necessary to ensure that IOUs can raise sufficient capital to make improvements to infrastructure, and that a low ROE would increase customer costs in the long run by hurting SCE's credit rating.

SDG&E made similar comments, arguing that SDG&E needs access to capital markets to fund wildfire mitigation efforts, among other investments. If ROE is set too low, it would force SDG&E to rely more on debt financing which would hurt SDG&E's credit ratings and increase borrowing costs. This would be passed on to ratepayers. SDG&E also said that financial stability of the company is important in the context of the ongoing pandemic; COVID-19 protections have led to a doubling of delinquent account balances in 2020 compared to 2019. SDG&E says that it needs to be financially sound to fund the growing undercollection of delinquent account balances.

CSE questioned why the authorized ROEs for California IOUs have not been reduced considering interest rates on borrowed money having fallen to historically low levels. They suggested that the CPUC consider whether the gap between the cost of equity and the cost of debt is justified. Furthermore, CSE recommended looking into the ratio between debt and equity, and whether it makes sense for IOUs to take on more debt.

Indivisible, CACE, and SSRF urged the CPUC to reduce the IOUs authorized ROE.

MRC also said that it is unacceptable for the CPUC to be authorizing exorbitant profits for IOUs in the middle of a pandemic and economic recession when the IOUs' grids have had several prolonged shutoffs. They said that the CPUC should minimize capital investments in order to reduce shareholder returns and provide relief to ratepayers.

Wildfire Costs

Comments specifically about wildfire costs were submitted by PG&E and SCE. Some stakeholders also made references to wildfire costs in their comments while discussing other issues, but those are captured under the other topic headings.

PG&E used their comments to draw attention to how highly uncertain wildfire costs will be over the next few years, and as a result how uncertain the white paper's rate projections are. PG&E recognized that there is limited information on which to base any projections for wildfire costs, and revenue requirement in general, and that the approach taken in the white paper is based on the best information available at the time. However, there is still significant uncertainty as demonstrated by the fact that the white paper provides two scenarios related to wildfire mitigation costs.

SCE highlighted the role that wildfire costs, particularly grid hardening, along with public purpose programs has had on rate growth. SCE argues that these investments are time sensitive given the existential risk that wildfires pose to Californians, and as such it is inappropriate to focus solely on electric rates growing faster than inflation. SCE also used their comments to reiterate the cost-saving potential of their customer-funded self-insurance proposal. SCE explained that AB 1054 requires IOUs to procure insurance for the first \$1 billion of coverage, which is currently costing SCE \$450 million/year and includes \$80 million of co-insurance and \$50 million of self-insured retention, making net coverage only \$870 million. SCE said that by self-insuring the company could save hundreds of millions of dollars, so long as actual claims do not exceed the avoided cost of insurance over a multi-year period.

Transmission Costs

Comments on transmission costs were submitted by PG&E, SCE, CEERT, 350 Bay Area, and unaffiliated commenter Jan Dietrick.

PG&E sought to more fully contextualize the white paper's discussion of historical transmission costs. First, PG&E said that the white paper highlights that the transmission access charge (TAC) has been increasing while gross system load has declined, but fails to mention that the growth of distributed resources has led to many customers using the grid as a "battery exporting surplus energy onto the system when the sun is shining and drawing energy from the grid after the sun sets." PG&E said that it would be better to compare TAC to total energy consumption, which is total energy demand inclusive of distributed generation. PG&E said that the white paper should also acknowledge that the "duck curve" (CAISO's term for the shape of the state's net load graph due to the renewable-driven midday trough and steep late afternoon/evening upward ramp) requires fast and flexible ramping, which is useful context when discussing increasing transmission costs. PG&E also suggested alternate ways of presenting the transmission cost data from the white paper.

PG&E pointed out that the 5-year, 21% increase in capital additions presented in the white paper is equivalent to an annual 3.9% increase over a 5-year period. PG&E also pointed out that the white paper states that the average age of a transmission asset is 36 years, but there are many different types of assets with very different

years of useful life. PG&E also objected to the white paper's direct comparison between PG&E, SCE, and SDG&E's transmission systems without any mention of the very different scale, terrain, and system needs in the different service territories.

SCE also sought to provide additional context for the rising transmission costs identified in the white paper. First, SCE emphasized that their transmission revenue requirement actually decreased between 2016 and 2021, unlike PG&E and SDG&E. SCE also said that the recent growth in transmission revenue requirement has been driven by several factors outside of IOU control: the state's renewable portfolio standard (RPS), long permitting processes, and changes to transmission projects' scopes, routes, and undergrounding obligations. SCE also responded to the white paper's assertion that Federal Energy Regulatory Commission (FERC) ROE incentives drive costs up by saying that "the incentives are designed to promote efficient use of transmission and provide other customer benefits through market efficiencies." SCE said that these incentives helped drive three key transmission projects which support greater renewable integration.

CEERT urged that a more comprehensive analysis of transmission costs is needed in order to balance the goals of decarbonizing the grid and mitigating rate and bill impacts. CEERT said that the white paper analysis does not sufficiently distinguish between wildfire mitigation, other capital investments, network expansion to support load growth, generator interconnection, and capital maintenance. These distinctions are needed in order to identify why rates are increasing and develop appropriate mitigation strategies. CEERT also says that evaluation of transmission costs should recognize which projects contribute to lower generation costs. CEERT also voiced their frustration with the new stakeholder transmission asset review (STAR) spreadsheet that is now being used to report transmission project costs because so many details were withheld due to confidentiality concerns.

350 Bay Area expressed their support for additional oversight of "self-approved" transmission projects and for elimination of the FERC incentive to participate in the CAISO, which is already required by state law. They also recommended that the CPUC look at "the impact of transmission cost allocation and the failure to incorporate ratepayer transmission cost impacts in procurement practices." According to 350 Bay Area, customers' transmission fees are based on metered electricity usage regardless of how much of their energy is sourced through transmission. They also said that in front of meter DERs are not properly modeled in IRP proceedings because models do not differentiate between resources that require transmission grid and those that do not.

Unaffiliated commenter Jan Dietrick expressed concern that transmission costs are rising faster than other electric costs. In particular, Dietrick advocated for TAC to be fairly allocated between IOU service territories and municipal utility territories. Dietrick also said that the price distortion blocks the development of renewable energy projects such as community microgrids, which is a particular problem in Santa Barbara County because it is located where PG&E and SCE's service territories meet.

Natural Gas Costs

Comments on natural gas costs were received from CEERT.

CEERT said that the white paper does not adequately consider natural gas rates and bills, which are also affordability issues. CEERT said that “burner tip” prices for natural gas have been very volatile in California over the past decade as a result of multiple disasters, and that this has implications for both natural gas and electric rates. These disasters, which include the San Bruno explosion and the Aliso Canyon disaster, have necessitated significant investment in natural gas infrastructure which has the same affordability and equity implications that were discussed in the context of electric bills in the white paper. Furthermore, CEERT said that gas and electric prices are linked due to continued over-reliance on natural gas generation. When natural gas prices spike, it causes electric spot prices to spike which gets recovered from customers through the energy resource recovery account (ERRA). However, CEERT says that the “ERRA trigger” that initiates a CPUC investigation into price spikes has only occurred once in last 10 years, showing how little monitoring there is of gas price volatility.

Alternative Revenue Sources, Rate Structures, Cost Saving Opportunities, and Ideas for Improving the Ratemaking Process

This section covers recommendations made by stakeholders for offsetting IOU revenue requirements, changing the electric rate structure in order to address equity and cost recovery concerns, reducing costs, and improving the ratemaking approval process. Comments were submitted by PG&E, SCE, SDG&E, CEERT, CSE, American Clean Power (ACP), Indivisible, CACE, and SSRF.

PG&E agreed with some of the panelists in that using energy bills alone to pay for climate programs is regressive and deters electricity use even as the state is trying to promote electrification. They said that non-energy bill funding can be more progressive than volumetric energy rates, and PG&E was encouraged that some panelists suggested “regional pricing, pricing for T&D assets tied to locational risk, progressive flat-rate components, rate design approaches that preserve marginal pricing, tax funding of energy bill components, and decision-making that would expand to include more non-energy-industry and climate-affected parties.” Commenting on the white paper’s bill projections for a hypothetical customer in a hot climate zone, PG&E noted that customers in hot climate zones pay a disproportionate amount for fixed costs compared to low usage customers. PG&E encouraged adoption of residential fixed charges to reduce volumetric rates, better represent cost causation, and reduce the disincentive for electrification.

SCE provided several recommendations for cost reduction. In addition to the customer-funded self-insurance proposal described previously, SCE advocated for eliminating the fixed energy price option for must-take contracts with qualifying facilities (QFs). SCE says that this would prevent procurement from QFs at above market prices. FERC Order 872 eliminated this option, but the CPUC has not followed suit. SCE also recommended extending the Southern California Gas (SoCalGas) operational flow order (OFO) reduced penalty structure during summer months because this would stabilize gas prices, which would thus stabilize electricity prices. This provision is currently scheduled to sunset in September 2021. SCE also recommended allowing IOUs more flexibility in selling renewable energy credits (RECs) by making three changes: permitting sales of RECs below annual RPS targets while still using Tier 1 advice letters, eliminating price floor on RECs,

and allowing contract terms of up to 10 years. Finally, SCE agreed with the proposal from some of the panelists to fund public policy programs through statewide funding.

SDG&E agreed with Professor Borenstein's proposal to allow for fixed cost recovery outside of volumetric rates through a progressive fixed charge structure. SDG&E said that this proposal would prevent avoidance of fixed costs, lower volumetric rates, and reduce disincentives for electrification without having to resort to technology-specific tariffs. However, they noted that implementing such a proposal would require legislative action since there are currently limits on fixed charges.

CEERT strongly recommended that the CPUC explore options to fund transmission expenses in such a way that they are not shouldered by ratepayers. They note that the FERC-regulated TAC allows a generous rate of return that they say is the equivalent of an 18% interest rate for financing those investments. Instead, CEERT suggested evaluating the proposal put forward by Betony Jones (sic: this was proposed by Jennifer Dowdell) of publicly financed or state-owned transmission assets. They noted that using a tax free, state backed revenue bond to finance transmission expenditures would yield an interest rate of about 5%. CEERT also recommended looking into cooperative development of transmission projects with municipal utilities.

CSE provided extensive comments on the CPUC's ratemaking process and how to improve it. CSE recommended that the CPUC take control of the rate setting narrative by telling IOUs that rates need to be at a certain level as a starting point for rate case applications rather than allowing IOUs to apply for a certain amount of revenue requirement. CSE said that this would put the burden on the IOUs to find ways to reduce costs. CSE also said that the current rate setting process allows IOUs to propose a certain amount of spending and only respond to specific objections brought forward by parties, rather than justifying all spending. Furthermore, CSE said that the CPUC has become too reliant on settlement negotiations. According to CSE, settlements do not ensure that the revenue requests are reasonable, and adoption of settlements over multiple cycles has eroded the CPUC's ability to hold IOUs responsible for its spending. The CPUC should instead fully review requests.

CSE also agreed with panelists' proposals to shift funding for programs that provide societal benefits from ratepayers to taxpayers. According to CSE, this would be less regressive and would also reduce geographic cross-subsidization, such as when customers of a utility in areas that are not prone to wildfires have to pay for equipment hardening in the same utility's wildfire-prone areas. Finally, CSE recommended allowing fixed charges, arguing that it is questionable whether high volumetric rates actually drive conservation since customers only care about their bills rather than the rates that determine them. CSE argued that high volumetric rates might discourage home and vehicle electrification without changing other usage behavior.

ACP noted that there is a proposal under consideration in the public charge indifference adjustment (PCIA) rulemaking for reallocating products within utilities' portfolios (PCIA Working Group 3 Final Report) which they support. ACP supports this proposal because it would right-size the IOUs' supply portfolios which is important considering the amount of load shifting that is expected.

Indivisible, CACE, and SSRF said that the CPUC should stop and investigate IOU lobbying and advocacy that is funded by ratepayer dollars.

General Comments, Drivers of Rate Growth, and Improvements to Modeling

General comments not covered in the other topic categories, including comments on general drivers of rate growth and suggestions for improvements to the white paper and the rate modeling, are summarized here. Comments covered include those submitted by PG&E, SCE, SDG&E, TURN, the Western States Petroleum Association (WSPA), Indivisible, CACE, SSRF, 350 Bay Area, and ACP.

PG&E discussed the drivers of rate growth, which include not just the cost of climate change initiatives but the impacts of climate change as well. These costs are high and growing. PG&E also discussed the uncertainty in the rate forecasting, which include uncertainty in future revenue requirements (as described previously when discussing wildfire costs) as well as uncertainty in electric sales. EVs and building electrification may contribute to significant sales growth, but that uncertain growth may not be adequately captured in the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), which was one of the main inputs for the rate forecast presented in the white paper. PG&E also appreciated the use of the cost and rate tracking (CRT) tool in the rates analysis and looks forward to continuing to develop this tool with the CPUC.

SCE talked about the time-sensitive nature of the grid hardening and clean energy programs funded through rates, and how that should be taken into account when considering the pace of rate growth. SCE said that they have kept rate growth lower than the other IOUs and lower than inflation over the past few decades, but that is no longer possible given the wildfire and climate challenges the state now faces. These investments should be viewed in terms of the benefits they provide in addition to the costs they impose.

SDG&E identified the main drivers of their rate increases: transmission and distribution investments (including wildfire mitigation), public purpose programs, technology subsidies, and a decline in sales due to successful energy efficiency and DER programs. SDG&E also said that their bills remain low compared to other IOUs nationwide, and because incomes in their territory are higher than average as well, electricity burden is lower than average compared to the other California IOUs.

TURN provided a number of recommendations for improving the rate modeling, as well as suggestions for sensitivity scenarios to consider. TURN suggested that the CRT be run for a range of scenarios rather than a single scenario to help understand the implications of uncertainty surrounding a few of the key inputs. TURN was only able to provide suggestions for scenarios based on PG&E's CRT model, since the other IOUs have not made their models publicly available. The additional scenarios they recommended address the uncertainty in revenue requirement growth, especially transmission and distribution revenue requirement, as well as uncertainty in the sales forecast. They also suggested an additional sensitivity scenario for higher than expected wildfire and clean energy infrastructure spending. Finally, TURN recommended presenting results for CARE and non-CARE rates separately.

WSPA expressed concern that the white paper did not address costs and affordability for all rate classes. Specifically, the paper did not address commercial and industrial (C&I) customers. WSPA warned that if rates for these customers become too burdensome, they may elect to secure alternative electric services which would have negative consequences for residential customers. WSPA referenced Energy Information

Administration (EIA) data that they say shows that California's industrial rates are non-competitive and excessive today, and will worsen if they take the same trajectory as the forecasted residential rates. According to WSPA, the EIA data shows an inverse relationship between electric rates and C&I demand and revenue contributions, which is a warning sign if C&I rates are expected to increase. Costs that are currently allocated to C&I customers would be shifted to residential customers.

350 Bay Area recommended specific wording changes to strengthen the white paper.

ACP provided feedback on PG&E's proposed cost-cutting ideas, saying that they are uninformative and vague. ACP felt that PG&E should instead talk about how it can use its revenue requirement more effectively to meet its obligations as a Transmission Owner. ACP also discussed how the drop in the cost of utility-scale renewables, combined with the recent extension of federal tax incentives for renewables projects, could benefit Californians if the state provides direction for near-term procurement of new renewables resources. ACP also provided recommendations for improving the Historical Cost and Rate Trends section of the white paper. Specifically, they said the paper should evaluate how past investments in bulk transmission have enabled clean energy resources to compete for power contracts, thus reducing the generation component of rates. Finally, ACP recommended including in the discussion of affordability that clean energy provides high paying jobs for low-income households.

Indivisible, CACE, and SSRF said that the white paper identifies the major reasons behind increasing electric bills: excessive transmission spending, wildfire mitigation costs, and IOU ROE. In their opinion, the IOUs do not care about affordability and equity, and are using these talking points as propaganda to oppose DERs.

ADDENDUM 3: ADDITIONAL CONSIDERATIONS ON CUSTOMER EQUITY AND THE AFFORDABILITY EVALUATION FRAMEWORK – DAVID ROLAND-HOLST (UC BERKELEY)

Background

Setting electricity rates is one of the most consequential policy responsibilities in California. These administered prices drive primary energy use, technology investment, and billions of dollars of enterprise and household expenditure across the world's fifth largest economy. For these reasons, decisions in the rate setting process should be supported by the highest quality data and assessment methods. Fortunately, today's information and analysis technologies offer unprecedented detail and timeliness of data and sophisticated tools for analysis and forecasting. With the right combination of institutional and independent partners, the CPUC can make investments that most effectively support robust decision making, transparent stakeholder engagement, and fulfill its multifaceted goals for economic and social progress in California.

This section focuses on a few issues related to formation of rate policy and assessment of rate impacts. In particular, these notes discuss existing approaches to estimation of past, present, and future rate impacts and discuss opportunities for developing new data and analytical resources to improve these. The discussion will address three primary topics:

- Policy Coherence – Rate Policy in a Statewide Context
- Affordability/Equity Issues
 - a. Heterogeneity of affordability
 - b. Demand inelasticity for electricity, especially among low-income customers
 - c. Rates as a mechanism for addressing equity issues
- Investing in Assessment and Decision Support Capacity
 - a. Time Horizon
 - b. Uncertainty
 - c. Stakeholder Engagement and Policy Dialog

Policy Coherence

Before examining more detailed issues of rate policy, it is worth considering this in a larger, multi-agency setting. The macroeconomic, technological, and social significance of electricity rate policy has already been emphasized, but the implications of this for “coherence” with other state policy deserves careful consideration. The CPUC's regulatory mission is clearly defined, yet its policies inevitably interact with actions and goals of other public institutions. To the extent that these are complementary, policy coherence can achieve synergies for effective use of public resources. In other circumstances, policies may offset or even conflict with one another. One example of this is reconciling emergent climate risks with existing ones.

The state's path breaking climate initiatives are based on shared perception of the future costs of global warming. While these were firmly established on the basis of information available during the legislative run-up to AB32 and in subsequent iterations of the Scoping Plan, RPS, SB350, etc., more recent experience has dramatically escalated and foreshortened these risks. Rapidly changing events, like recent catastrophic wildfires, present a challenge to policy coherence if short term risk management "crowds out" longer-term commitments because of fiscal constraints. Both types of defensive public investment remain necessary, and if new fiscal commitment is needed it is important to consider not just averted damages but the real and lasting benefits from all types of climate investments. Empirical studies have identified direct and indirect benefits of California's renewable energy buildout, including job creation, public health benefits, and savings to energy users and all those who benefit indirectly from their expenditures on other goods and services. Depending upon the economic and air quality benefits associated with renewable deployment, postponing such investments will differentially impact Californians in important ways. Examples below illustrate this.

Of course, deferring renewable deployment would also have costs, both in terms of elevated climate risk/damage and health impacts of continued reliance on more emission-intensive power generation. A recent example of this occurred when uncertainty about current and future renewable capacity contributed to delaying retirement of backstop gas generation plants around the state.²¹⁷

In other cases, there is less direct contention between objectives, but incremental costs may have to be covered to reconcile them. An important example of this is the "Build Back Better" agenda, committing replacement and renewal of infrastructure to higher standards of mitigation and climate resilience.

²¹⁷ Wood Mackenzie. "California's power market balancing act: Why the state won't let go of nine gas plants set to retire this year." August, 2020. <https://www.woodmac.com/news/editorial/californias-balancing-act/californias-power-market-balancing-act-full-report/>

Example: The Water/Energy Nexus

Electric power and water are essential resources for California. Since the of both are significantly regulated and intimately linked across the economy, it is reasonable to ask if more coherent policies could improve their services, e.g. making them more affordable, inclusive, or sustainable. The term “Water/Energy Nexus” refers to the state’s extensive use of energy services for water conveyance, heating, and treatment. Taken together, these uses comprise a substantial share of state electric power demand, representing significant direct and indirect costs for public and private rate payers. In recognition of this, the CPUC has for years sponsored programs and decision support tools to promote water use efficiency and cost-effectiveness. What has received less attention recently is the potential for water services to support electric power. This perspective is changing because of two important trends: rapid expansion of intermittent renewable energy and emerging needs for more water storage capacity to compensate for early runoff. In particular, research on pumped hydropower storage and allied technologies has the potential to transform state water infrastructure in the service of greater renewable capacity use, water conservation, and more cost-effective grid development.^{218,219}

Because of spatial mismatches between renewable water supplies and demand, California has a very extensive water conveyance system, including the flagship California Aqueduct, a system of canals, tunnels, and pipelines extending over 600 miles across the state. Recognizing the energy storage potential of water, the Aqueduct already includes many pumping stations to lift water over higher elevations, complemented by hydropower stations to recover energy from the descending water. While these increase the efficiency of statewide conveyance, they only realize a fraction of the energy potential that could be captured by integrating solar and wind power resources. Such a system would combine renewable power sites with higher elevation reservoirs and paired pumping-hydropower facilities to fill them using surplus and intermittent power. Releases back into the aqueduct or other state canals can be timed to smooth water transfers and reduce upstream peak load pumping. State canals like the aqueduct can even contribute to renewable capacity by covering them with solar panels, utilizing a large existing easement for clean power production and reducing evaporation loss.²²⁰ Finally, spatial dispersion of these water/energy resources makes them ideal candidates for local public/private investment partnerships that promote local investment, employment, clean energy, and water use efficiency.

Equity Issues and Energy Affordability

Heterogeneity of Affordability

California state agencies are ever more aware of the importance of accounting for more diverse stakeholder interests and most are making substantial investments in assessment and decision tools that recognize this. The CPUC is no exception and has funded significant efforts to better address differentiated ratepayer needs and economic circumstances in ways that advance state policy objectives. These efforts should be reaffirmed

²¹⁸ Hunt, Julian D., Edward Byers, Yoshihide Wada, Simon Parkinson, David E. H. J. Gernaat, Simon Langan, Detlef P. van Vuuren, Keywan Riahi. “Global resource potential of seasonal pumped hydropower storage for energy and water storage.” *Nature Communications*, 2020; 11 (1) DOI: 10.1038/s41467-020-14555-y

²¹⁹ <https://www.sciencedaily.com/releases/2020/02/200219152854.htm>

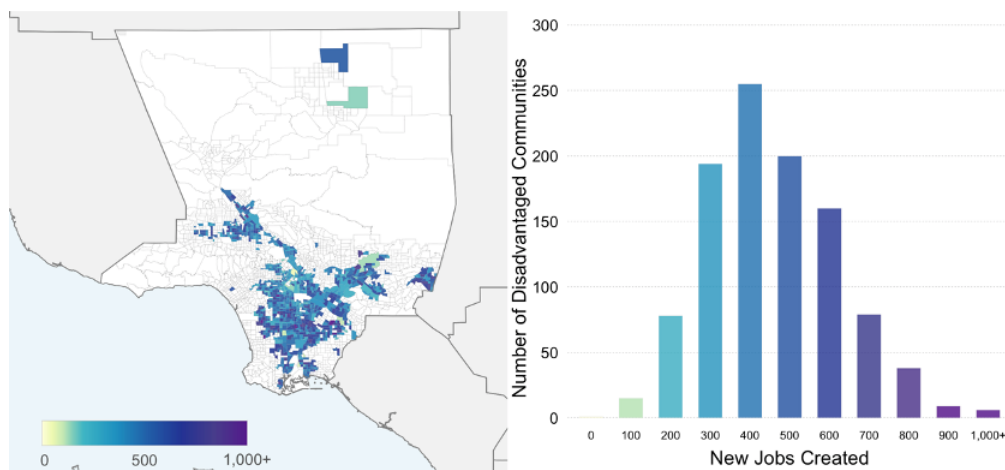
²²⁰ A recent UC Davis study estimated these losses to be 27 acre-foot/day, or about 20,000 acre-foot/year. At a price of \$107 per acre-foot, the total cost of evaporation comes to over 2 million dollars per year that is lost due to evaporation.

with new and more determined commitments to use the state’s rich data resources for more effective policy targeting.

More fully identifying the heterogeneity in affordability among the state’s residents is vital to helping those who are most at risk of losing utility services due to non-payment or having to forego spending on other essential goods and services. Past efforts to characterize electricity affordability have relied on overly broad metrics which measure changes in average rates and bills for entire IOU service territories or even for the entire state. Because of income and wealth inequalities, which have grown wider in recent decades, this approach can fail to identify specific communities where high electric bills are more of an affordability concern than they are for the average residential customer. The CPUC’s recently developed affordability metrics as part of R.18-07-006 seek to incorporate these socioeconomic considerations into evaluations of utility service affordability.

Example: Employment and Public Health Benefits of Renewable Energy Deployment

**Figure 1: Job Creation: Disadvantaged Communities in Los Angeles
Median Scenario for LTES**



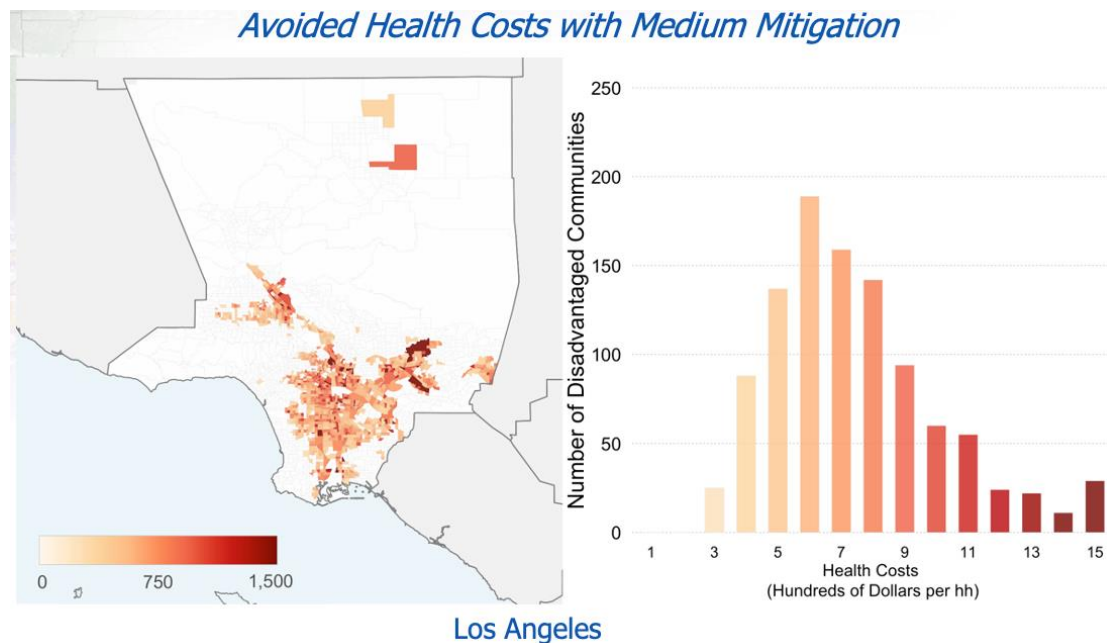
- Because workers in DACs are disproportionately employed in service and construction industries, 475,000 of the 940,000 jobs created are in Los Angeles are in DACs (50%).
- On average, 500 jobs created per DAC and more than 1,000 jobs created in five DACs.

Extensive research has already documented that the impacts of climate change are likely to disproportionately impact the state’s Disadvantaged Communities (DACs). It is essential that distributional economic impacts be incorporated into ongoing state policy deliberations to identify how benefits and costs are borne across diverse communities. Two studies for the CEC and CAISO evaluated the economic stimulus and air quality benefits from measures included in California Senate Bill 350 and Executive Order B-30-15.²²¹ Using a long-term forecasting model, this assessment identified job creation and health benefits across the state’s DACs. More specifically, this hi-resolution spatial analysis revealed that renewable energy investments actually created

²²¹ <http://bearecon.com/portfolio-item/cec-ltes/> and <http://bearecon.com/portfolio-item/caiso-sb350/>

a higher proportion of new jobs as well as higher absolute and relative health benefits in these low-income areas than for non-DACs.

Figure 2: Sample DAC Air Quality Scenario Results



- Average DAC households avoid \$677/hh in costs while non-DACS avoid \$511/hh.
- Los Angeles includes DACs with some of the highest PM 2.5 exposure (~90th percentile), Ozone exposure (~93rd percentile) and disease incidence (~99th percentile in asthma).
- Avoided health costs due to predicted reduction in both PM2.5 and Ozone concentrations in the region.

Demand inelasticity for electricity, especially among low-income customers

Energy efficiency and affordability are both laudable policy goals, but they differ in important ways and can be partially conflicting, especially in an energy market with heterogeneous actors. The ability of customers to manage their energy consumption depends on the particular characteristics of residential and commercial users. As a practical matter, this means rate setting and allied policies must be designed and implemented carefully and supported by the best available information. Here only a few salient issues on the demand side are highlighted.

Commercial demand in California has been relatively stable in composition, although emergent opportunities for independent renewable development and combined heat and power have eroded demand and, as discussed in an example below, undermined the capacity of tiered pricing to cover legacy infrastructure and power contracting costs. In recent years, large new energy-intensive users like data farms have also created new models of self-sufficiency, using distributed generation, storage, and integration technologies that are increasingly scalable. Despite these technical disruptions, however, the commercial side of electricity demand remains the most predictable and financially sound part of the IOU-serviced market.

Residential demand is differentiated along several important dimensions. Firstly, and fundamentally, the residential consumer population is divided between homeowners and tenants whose property is owned by someone else.²²² Rate changes have different effects on these groups. For owners, higher rates present an incentive to invest in distributed energy resources. For tenants, who rarely invest in durable appliances or efficiency retrofits, higher rates simply encourage them to ration energy use.

Lower income households tend to be tenants. This means their energy demand is intrinsically more inflexible (inelastic) for several reasons. Firstly, they do not have discretion or even purchasing power to replace durable appliances or retrofit their premises. Second, if they are already constrained to meeting only their basic energy needs, rate increases may not result in substantial reduction in energy use but rather deprive them of other consumption goods and services. Finally, the same constraints imply that rate reduction (by subsidy or otherwise) may sharply increase their demand. The last two conditions imply that demand response is asymmetric, inelastic to rate increases but elastic to rate reduction – doubly difficult to predict.

Affordability is certainly an appropriate policy objective with respect to low-income customers, and means-calibrated rate setting can address this with available information, but reasoning presented in the next section, suggests that (per capita) basic need subsidies may be a more effective policy instrument. More subtle functional diversity also exists within income groups. For example, residential customers at most income levels will have different adjustment options, and be impacted differentially, depending on their ownership status. Because tenants may lack property rights to choose technologies, as well as collateral to finance technology adoption, this group should probably be treated differently, especially in income categories where energy services are less affordable. Ultimately, then, like student financial aid, affordability policies should account for assets as well as income.

To summarize, for policy goals related to energy efficiency and its attendant economic and environmental benefits, rates are less effective policy instruments when targeting lower income households for three reasons.

- A higher proportion of low-income energy demand is not discretionary, meaning their demand response will be more inelastic against rising rates.
- Many low-income groups have more limited options for choosing energy use technologies, from used (less efficient) cars to appliances and home (e.g. insulation) investment choices (made not by them but by their landlords).
- Tenancy can undermine the potential for rates to stimulate adoption of more energy efficient technologies. This can be better be achieved by incentives that target landlords.

Generally speaking, much more research is needed on demand responsiveness to retail electricity rates, taking account of both income and asset ownership patterns.

²²² Strictly speaking, this is also true of commercial users (especially small businesses), but household demand is a category where heterogeneity has greater policy significance.

Rates as a mechanism for addressing equity and welfare issues

Finally, it should be recognized that rate structure is a relatively inefficient instrument to advance either efficiency or equity objectives. Standards and owner incentives can be more effective ways to promote efficient technology adoption.

From the equity perspective, energy affordability is part of a larger policy agenda of social protection, securing basic needs for lower income groups so they have adequate energy services and are not paying for them at the expense of other necessities. A large body of public health evidence suggests that energy rationing is detrimental to health and other dimensions of human welfare, and strategies of this kind are nearly universal in more advanced economies.^{223,224} Typically, however, they are recognized and managed as incomes policies and administered by fiscal agencies. One of the most important examples of this is food stamps, which secures purchasing power for essential nutrition. Although the policy targets an essential commodity, it is not administered at the sector level – neither USDA, the agrifood sector, nor other food consumers are responsible for managing or financing this program (except as general taxpayers).

In addition to discussing expected rate, bill, and affordability changes based on the modeling work done for this white paper and other sponsored research, it is worth discussing the uncertainty inherent in some of the underlying assumptions and how the rate and affordability evaluation framework in general can be improved.

Investing in Assessment and Decision Support Capacity

The complexity of today's energy economy is such that policies based on intuition, rule-of-thumb, or short-term deterministic partial equilibrium models are unlikely to achieve anything approaching optimality. The CPUC should consider further investments in decision support. By comparison to past decades, there are now important data and assessment technologies available to strengthen the CPUC's capacity for policy design and implementation. The following represent broad categories of technical capacity, and more detailed needs assessment is recommended in each context.²²⁵

Time Horizon

There is currently a temporal mismatch between some electric power sector modeling (1-2 years; IEPR and RESOLVE are exceptions here) and state energy/climate policy horizons and milestones (decadal) – where longer term models are needed. The result is a lower degree of coherence in interagency policy and statewide policy dialog. The burden of expanding modeling can be shared to some extent across agencies, but even for individual use these models do not need to be built from scratch. In other words, agency investments can complement each other and investments can be made in competitive independent information resources and expertise. For example, state budget decision making is supported by dynamic forecasting under the

²²³ Jessel, Sonal, Samantha Sawyer, and Diana Hernández. "Energy, poverty, and health in climate change: a comprehensive review of an emerging literature." *Frontiers in public health* 7 (2019): 357.

²²⁴ Thomson, Harriet, Carolyn Snell, and Stefan Bouzarovski. "Health, well-being and energy poverty in Europe: A comparative study of 32 European countries." *International Journal of Environmental Research and Public Health* 14, no. 6 (2017): 584.

²²⁵ With respect to this and related capacity needs, assessment could be done internally or as part of independent program reviews.

supervision of the Department of Finance, using a combination of internal, shorter term models and external (commercial) national and global forecasting models.

Uncertainty

Uncertainty is endemic to all forecasting, but modern assessment tools seek to limit this as a policy risk by modeling uncertainty explicitly. In the present context, relevant risks relate to the impacts of rate decisions based on limited information about future costs and other market decisions. Most of the CPUC's current decision support models (CRT, RECC) could benefit from more statistically robust scenario tools that explicitly recognize any uncertainty and measure its potential risks. In addition to "natural" uncertainty arising continuously from world events, risks in energy modeling can arise from behavioral responses and modeling bias.

Example: Unintended Consequences of Electricity Rate Stratification

A primary source of policy uncertainty arises from behavior, i.e. responses to rate making decisions that alter use or technology adoption patterns. Assuming that these remain relatively constant, rate change can lead to unwelcome surprises, as the following two examples make clear.

Industrial rates - for a variety of reasons, but usually because of large, fixed cost commitments (infrastructure or long-term contracting), average total system costs can rise above marginal costs. If rate structure is "progressive", rate stratification tends to shift these fixed costs to higher tiers. This approach creates incentives for financially able ratepayers to invest in independent power sources, opting out of higher tiers, undermining the financial integrity and perhaps the equity objectives of the rate structure.

Residential rates - a similar situation arose in residential electricity markets with household PV promotion about two decades ago. At that time, stratified rates increased the incentive for wealthier households to invest enough in PV to "drop down" in the rate structure, offsetting enough of their load to evade the progressive rates for the same (or even greater) total household energy consumption. Again, differentiated rates created "adverse selection" - defection of higher income customers from higher tiers, undermining system financing and equity objectives.

The most effective defense against this kind of uncertainty is systematic ex ante assessment, usually done with policy scenario modeling as part of established forecasting activity. This can be in-house or competitively provided but should be vetted by some kind of independent oversight such as a Technical Advisory Board or mandatory peer review. In most cases, this approach cannot eradicate policy risk but is more likely to promote adaptive response and investments in timely, high quality data. As part of a more complete assessment framework, three strategies can improve reliability against uncertainty.

Explicit Risk Modeling or Sensitivity Analysis

Thanks to over 50 years of statistical work in support of strategic policy making, there is now a large suite of tools for modeling uncertainty. This is complemented by a vast amount of work in financial analysis, but those tools would be more relevant to regulated private enterprises. This general approach, called Monte Carlo methods, has been used for decades in finance and engineering to elucidate systemic uncertainties and manage attendant risk. Simpler “stress test” models of stochastic net present value inform most large project investments, but the spirit of all these approaches is the same. The same approach has been applied in economic forecasting, mainly intended to overcome uncertainty about underlying behavioral assumptions and states of nature.^{226,227,228} These analytical approaches strengthen capacity for early warning and adaptive policy.

Diversification of Data Sources

Assessment methods that rely on limited data are generally recognized to yield estimates with commensurately limited statistical confidence. When data may also be subject to reporting bias (conscious or otherwise), reliability is further undermined. Generally, the gold standard for statistical work, whether it be forecasting or cross-comparison, is randomized sampling with recourse to independent resampling and auditing. To limit the risk of weaker samples, a comparison framework that incorporates independent information is recommended. In this present context, this would mean cost and other data comparisons across a variety of electric power jurisdictions, nationally and even internationally, adjusting as appropriate for local resource costs. In addition to strengthening estimation confidence, this approach can help identify emerging disparities between local and economywide conditions, either of which might undermine policy effectiveness.

Example: Data Resources within the Industry

The rate setting process relies critically on IOU reporting of costs and related information, but there remain significant opportunities to leverage other information resources within the industry. As a result of decades of investment in one of the California's most inclusive supply chains (electricity services), the IOUs have an enormous reserve of data. In today's information economy, this data is an economic asset that, subject to appropriate use standards, could generate very substantial revenue for them and long-term innovation benefits for the overall state economy. Marketing IOU data would serve at least two important purposes: 1) Generate income that can offset required electricity revenue as well as emergent costs (e.g. wildfire); 2) Support broader innovation capacity in electric power, use technology, and many other dimensions of the state's energy system. California is home to some of the most innovative data use companies in the world, and their efforts to match increasingly diverse consumer populations with innovative technology and other producers of goods and services have dramatically increased rates of technology development and diffusion.

²²⁶ Thissen, Mark. A classification of uncertainty in empirical modelling. Graduate School/Research Institute Systems, Organisation and Management, 1998.

²²⁷ Belgodere, Antoine, and Charles Vellutini. "Identifying key elasticities in a forecasting model: a Monte Carlo approach." *Applied Economics Letters* 18, no. 17 (2011): 1619-1622.

²²⁸ Borenstein, Severin, James Bushnell, Frank A. Wolak, and Matthew Zaragoza-Watkins. "Expecting the unexpected: Emissions uncertainty and environmental market design." *American Economic Review* 109, no. 11 (2019): 3953-77.

Historical and Cross-Sector Comparison

A third approach to managing uncertainty in regulatory modeling is to evaluate assessment approaches over time and across the national electric power sector. Often called “back casting” or performance comparison, these approaches compare policy expectations at the time of enactment with subsequent outcomes, either confined to California or across a variety of regulatory jurisdictions. To the extent that disparities of outcomes (e.g. use patterns, profitability, etc.) diverge from expectations, and especially to the extent that such divergence is systematic, it may be possible to identify risks in current practices.

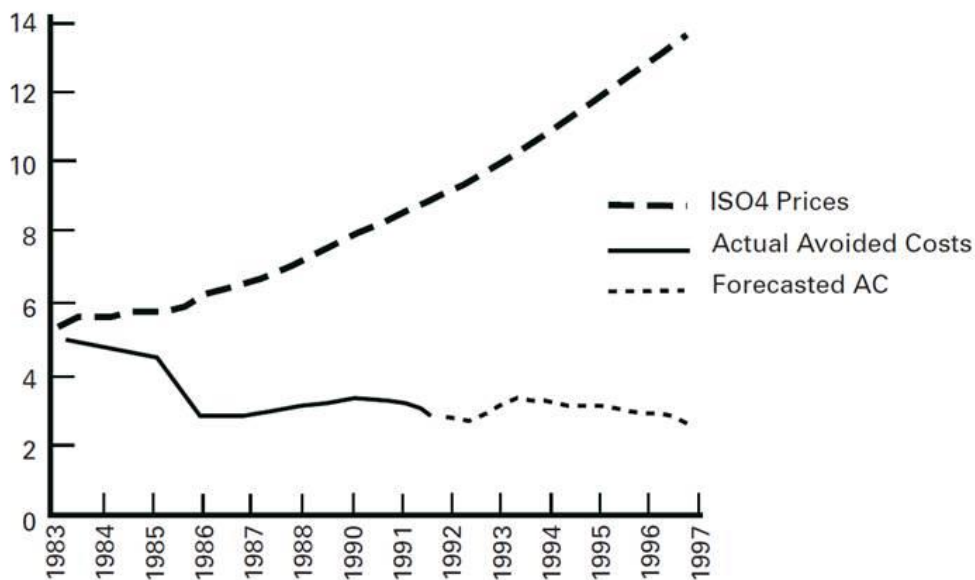
Example: ISO4 prices and avoided cost

In a 1993 report, the CPUC directed its Division of Strategic Planning to undertake a comprehensive review of the "...conditions the electric industry currently confronts, as well as future trends likely to influence the industry." This report concluded that the state should reform its regulatory program for two reasons:²²⁹

“California's current regulatory framework, significant portions of which were developed under circumstances that no longer obtain, is ill-suited to today's electric services industry.

The state's current regulatory approach may not be compatible with the industry structure likely to emerge in the ensuing decades.”

Figure 3: ISO4 Contract Prices and Observed Avoided Utility Costs



Primary evidence in the report included a contracting system called the Interim Standard Offer 4 (ISO4). Intended to limit risks to utilities from combined market and technology uncertainties that might seem familiar today, the ISO4 system was negotiated on the basis of the utilities' forecast of future fuel prices and other key assumptions needed to estimate long-run avoided costs. The result led to explosive oversubscription, with

²²⁹ <https://docs.cpuc.ca.gov/published/report/3822.htm>

15x the expected commitment from Qualifying Facilities that would be expected in a competitive market. The systematic gap in Figure 3 reveals two dangers that arise with regulated resource contracting: inflexibility and moral hazard. The first factor shifted the cost of systematic uncertainty to rate payers, while the second provided adverse incentives in negotiation, mainly biased disclosure of private information. As has been learned from Cap and Trade and related programs, tradeable rights systems can deliver efficiency without rigid contracts or disclosure requirements. These principles, independent evidence and adaptable, market-based policy instruments offer valuable guidance to navigate a new generation of systemic uncertainties.

Stakeholder Engagement

Although rarely acknowledged, one of the most important co-benefits of California’s pathbreaking climate policy initiatives is increased commitment to transparent and timely stakeholder engagement. Although it requires foresight and additional initial investment, more inclusive policy dialog generally yields more robust policy, recruiting beneficiaries to support decisions and identifying adjustment needs of others to improve those decisions. This kind of engagement is most effectively supported by public information about detailed policy impacts, and agencies that invest in this can greatly facilitate their progress toward stable long term policy implementation. In contrast, policies taken forward without timely and informed public engagement have often been vulnerable to legal and other challenges.

The most relevant capacity needs in this area are detailed data that reflect the essential heterogeneity across stakeholders including energy needs, use technologies, and socioeconomic initial conditions. We are fortunate to live in an era with relatively abundant data, and this can be leveraged with modern analytical and visualization tools to more effectively inform decision makers and stakeholders. By investing in this as internal capacity, agencies can “level the playing field” of policy awareness for smaller but much more numerous (enterprise and household) stakeholders on the demand side of electricity markets.

Example: EV Adoption Benefits the Overall Economy

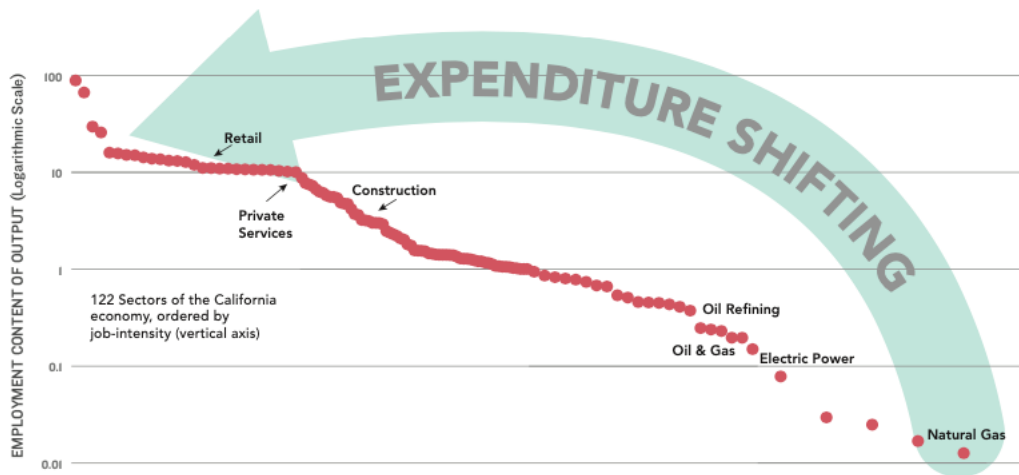
The capacity of detailed, forward looking policy assessment to inform public opinion is illustrated by a recent study of more rapid Electric Vehicle adoption.²³⁰ This independent analysis showed significant macroeconomic benefits and broad-based job creation, benefiting millions of Californians whether or not they buy an EV or the cars are made here. Like E3’s gasoline price scenarios and current research indicating that EV technology will lower vehicle costs, EV adoption can provide direct stimulus to California whether the state makes the cars or not. Growth stimulus from energy fuel saving is subtler, but also more pervasive. Promoting energy efficiency (in vehicles, appliances, or any durable goods) saves money for households and enterprises. These savings will be diverted to other expenditures, the majority of which (in California) go to in-state services that employ workers from all skill levels and demographics and are non-tradable, meaning these new jobs cannot be outsourced.

To see how potent this growth driver is, note that 70 percent of California aggregate demand (gross state product, or GSP) is household consumption and 70 percent of this goes to services. Thus, about half of incremental income or diverted expenditure can be expected to go to the service category of employment—

²³⁰ <https://www.next10.org/publications/ev-benefits>

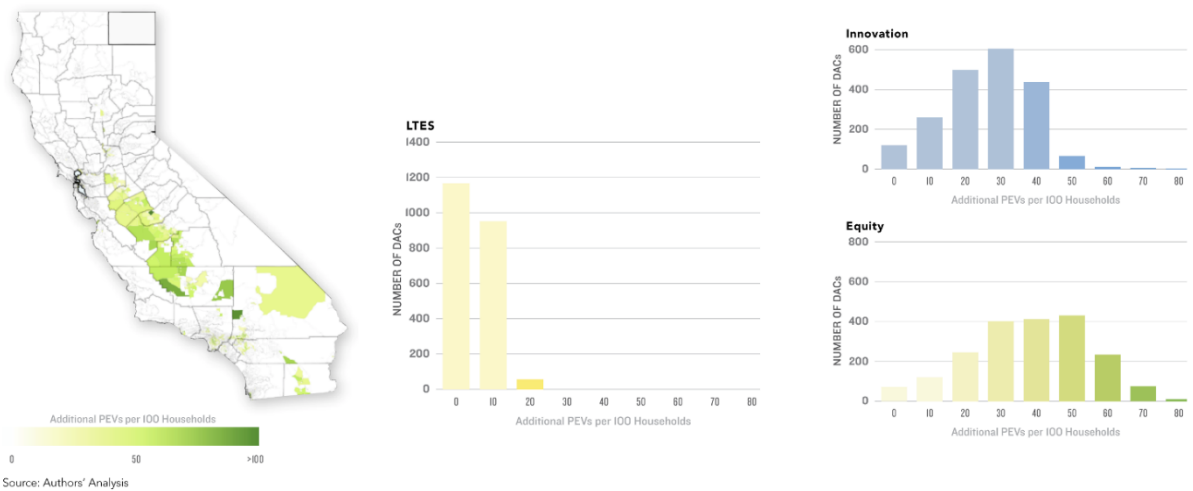
the most labor-intensive and skill-diverse in the economy. As Figure 4 makes clear, the carbon fuel supply chain is among the least employment intensive, and this after deducting a significant import cost share. Jobs per million of revenue in the service sector are one to 10 times greater than the same metric in the carbon fuel supply chain, and the difference is far too large to be offset by wage inequality. Simply put, if you save a dollar at the gas pump, you will spend about two-thirds of it on services, stimulating much stronger in-state job growth.

Figure 4: Job Creation Through Expenditure Shifting



Source: Authors calculations based on data from the US Bureau of Economic Analysis, US Bureau of Labor Statistics, and California Department of Finance⁷⁷

Figure 5: EV Adoption in Disadvantaged Communities



Source: Authors' Analysis

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ADDENDUM 4: CONCEPTS FOR EQUITABLE COST ALLOCATION AND EFFICIENT PRICING – MARK LEBEL AND CARL LINVILL (REGULATORY ASSISTANCE PROJECT)

Transportation Electrification Considerations

Consumer Economics of Transportation Electrification

Economics of transportation electrification should generally be based on total cost of ownership, where a comparison of fuel costs between two different vehicle types is only one component.²³¹ To understand the real choices that face consumers, the base price of the vehicles, any necessary upfront charging investments, non-fuel operation and maintenance costs, tax incentives, rebates, taxes and fees as well as the relative impacts of environmental regulations (e.g., the Zero-Emission Vehicle program from the California Air Resources Board) also need to be considered. Factors that are not strictly monetary will also impact consumer preferences, such as the availability of public charging to meet certain needs or the broader public health and societal impacts of different technologies. This means that many different policy levers can promote transportation electrification. Creating opportunities for low-cost EV charging, either through convenient time-varying rate differentials or a variety of other cost allocation and rate design options, can certainly help but should be viewed in this broader context.

In the earlier stages of transportation electrification, electric vehicles often had a substantially higher upfront price than internal combustion engine (ICE) options, even after rebates and tax incentives. This led, quite fairly, to an emphasis on the lower fuel and maintenance costs of electric options as ways to overcome that upfront disparity in the minds of consumers. However, as battery costs are dropping over time, vehicle price parity may be reached in the next few years, and there are scenarios where electric vehicles will be cheaper than comparable ICE options. Larger batteries and increased ranges are also improving the attractiveness of EVs to consumers. These changes may reduce the pressure on fueling costs as a key building block of the consumer case for EVs, at least for some market segments.

In this context, creating realistic weighted average fuel cost projections for different categories of transportation electrification could be a helpful step, that could reveal disparities across different market segments and geographies. Different EV charging applications fall into different customer classes with different rate structures and price levels, which in turn determine the cost of EV charging. For the residential market segment, many EV adopters may charge predominantly at home and pay on the basis of residential rate structures. However, most other charging applications will take place under commercial and industrial (C&I) rates. These C&I rates typically have substantial demand charges, which can adversely

²³¹ Beneficial Electrification of Transportation (Jan. 2019), pp. 29-33, Regulatory Assistance Project <https://www.raponline.org/knowledge-center/beneficial-electrification-of-transportation/>

impact the economics of EV charging.²³² Any EV adopters without dedicated parking at home may have higher costs due to frequent usage of public fast charging.²³³ Similarly, light-duty fleet electrification and medium- to heavy-duty electrification will be substantially impacted by demand charges. California has started to reform these rates for EV charging, but additional reforms will be needed.

Such a fuel cost analysis by segment can help public policy developments across the board, both for rate structures and the many other policy levers to accelerate equitable EV adoption. To the extent that the problem is either general (high rates across the board) or specific (high costs for certain types of transportation electrification), the solution could differ substantially. That could include efforts to hold down costs across the board or efforts to reform certain types of rate structures (e.g., demand charges). Narrowly tailored issues, either geographically or by market segment, may be easier to solve with reforms to electricity rate structures, particularly if win-win solutions can also promote efficiency and equity. To the extent that the issue is high electric costs generally, that may indicate that the best policy levers to promote electrification will be outside of electric regulation, through broadly available EV rebates or air quality regulations. A broad effort to shield EV charging from generally high electricity costs, through either discount rate options or separate EV rate classes, is possible to promote higher adoption rates. But such policies may primarily move those costs onto other customers.

Allocation of Costs for Transportation Electrification Programs

Over the past several years, California has developed a range of ambitious utility transportation electrification programs, whose costs will be recovered through electricity rates. This includes rebates for customer-owned charging stations, utility investments and expenses in make-ready infrastructure and charging equipment, and any directly related investments on the shared portion of the electricity system. To date, these costs have been recovered broadly across all customers and rate classes.

The question now: is there a more equitable and efficient way to charge these EV program costs, including specifically to EV adopters who benefit from these programs? In that context, it is important to recognize that EV adoption, and thus the utility programs that enable adoption, provide a range of ratepayer and societal benefits that should be properly accounted for.²³⁴ Furthermore, the purpose of these programs is to accelerate EV adoption, which could run counter to any effort to charge costs more specifically to EV drivers. That would particularly be the case with any market segments that are already facing unreasonably high charging costs, as discussed above. Utility EV use cases and customer behavior on new high powered

²³² Demand charge reform is likely worth pursuing beyond the context of transportation electrification, since most demand charges do not provide a good marginal cost price signal and do not allocate costs equitably across customers. See Demand Charges: What Are They Good For? (Nov. 2020), Regulatory Assistance Project: <https://www.raponline.org/knowledge-center/demand-charges-what-are-they-good-for/> and Smart Non-Residential Rate Design (Dec. 2017), Regulatory Assistance Project: <https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/>

²³³ Adding to the complexity of this analysis, many charging applications are not necessarily priced at the marginal cost of electricity but rather have prices based on a wider array of considerations depending on the service provider and the owners' business model. In some circumstances, this can mean free or low-cost charging as an amenity but, in other circumstances, this can lead to higher priced charging because it entails the recovery of other relevant costs, such as the end-use charging equipment, or the provision of bundled services. Of course, the relevant electricity rates will still influence decisions by the owners and operators of these charging stations, even if the final customer pricing is not directly linked.

²³⁴ The clearest example is demand management program costs specifically for EVs, whether they are integrated into utility TE programs or not, which should be treated like other demand management programs and allocated either on the basis of class participation or system benefits.

EV rate options (e.g., SDG&E’s new EV-HP rate and PG&E’s analog) will be evaluated carefully over the next year to assess whether and to what extent rate design tweaks will be necessary to promote more equity as California promotes swift adoption.

But in the longer term, striking a balance between goals of faster transportation electrification and equitable cost allocation should help promote the greater good.²³⁵ One set of options would involve changing the nature of the programs themselves. For example, instead of spreading costs of individual projects across many customers, the programs could effectively be used for **on-bill financing** of each project, where the customer who benefits pays off the utility costs of their own installation over time. “Pay-as-you-save” features can be incorporated in these programs so that customers are guaranteed to save on their monthly bills from day one.²³⁶

Another set of options would still spread individual project costs over groups of customers but in a more targeted fashion. In general, a portion of transportation electrification program costs could be directly allocated to a category of identifiable EV accounts, either accounts who have participated in a utility EV program (perhaps starting from a certain cutoff date) or any other administratively feasible way to identify EV customers. To take a more specific illustrative example, make-ready costs for a broad category of level two charging stations could be tracked and program participants in this category, possibly exempting certain participants that meet certainty equity criteria with respect to low-income and disadvantaged communities, would have a rate rider that includes recovery of some or all of those costs. Such an approach does have additional administrative costs compared to a more traditional broad brush allocation technique. However, nearly any approach to target costs more specifically to participants will share those difficulties.

Equity Considerations for a Robust Distributed Energy Resources Future

California, as a leader in the development of distributed solar, has been at the forefront of measures to reform compensation for customer-sited renewable generation. Starting from a simple net energy metering (“NEM”) policy of retail rate credits and monthly netting, the California PUC laid out a roadmap in 2016 for a bundle of reforms called “NEM 2.0”:

- Modest one-time interconnection charges;
- A requirement for NEM customers to be on a time-of-use rate, with netting taking place within each one-hour period; and
- Non-bypassable charges (which cannot be offset by credits) are billed based on a more granular measurement of all imports from the distribution grid.

As distributed solar penetration continues to grow in California, additional steps can be taken to improve the cost-causation basis of rate design for customer-sited renewable generation, including solar but potentially

²³⁵ See Electric Cost Allocation for a New Era: A Manual (Jan. 2020) pp. 86-89, Regulatory Assistance Project: <https://www.raonline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf>

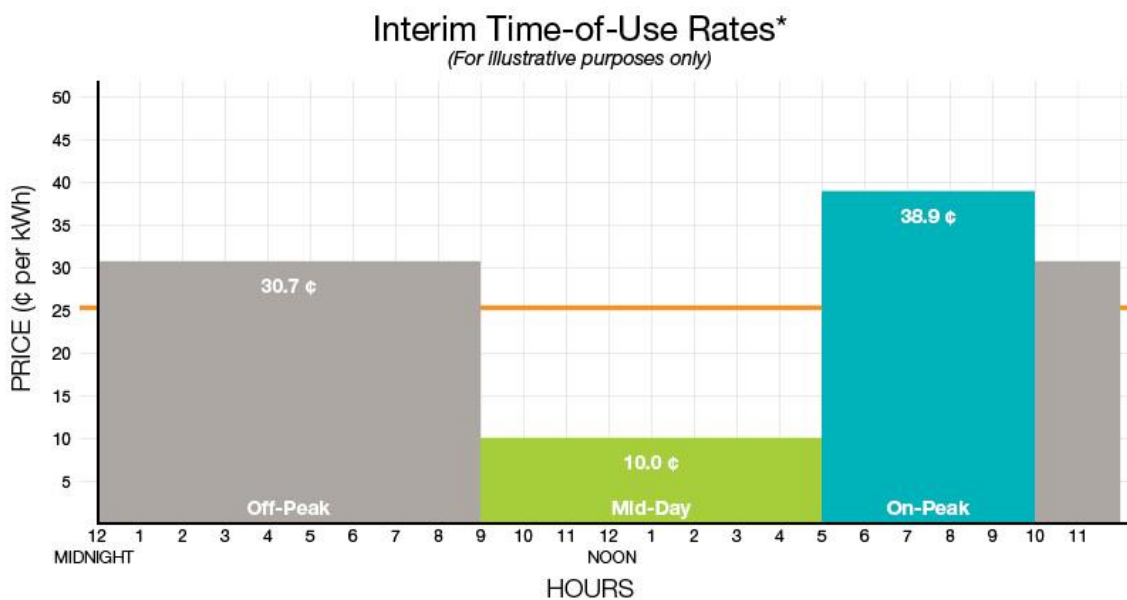
²³⁶ <https://www.cleanenergyworks.org/clean-transit/>

extending to other technologies that allow customers to export energy to the grid like storage, and ensure equitable allocation of costs. Gradualism will continue to be an important principle as these transitions happen, both for any current net energy metering customers who are placed on new rate structures,²³⁷ but also for clean energy industries who must adapt to new economic considerations.

Balancing granularity with understandability for small customers

A moderate path for reform would be to keep “net energy metering” as a mechanism but continue to change the specifics of how it operates. More granular time-varying rates would improve the economic basis of distributed energy resource compensation under net energy metering – naturally reducing any hidden cost shifts and incentivizing smarter customer behavior (load management, storage, and generation to the extent dispatchable). This transition would need to be balanced with customer understandability and the reality that some cost shifts will be contained in any broad rate structures.

For residential and small commercial customer classes, hourly pricing would be too complex in most cases until sophisticated energy management technology is widely available and affordable. Moving from relatively simple TOU rates - two- or three-periods and winter/summer seasons – to more sophisticated TOU rates – three- or four-periods and improved seasonal distinctions – with a critical peak pricing element, should be a significant improvement towards the ultimate goal of smarter pricing for all customers and equitable and efficient cost allocation.²³⁸



*Illustration reflects January 2021 O'ahu electric rates with applicable surcharges.

<https://www.hawaiielectric.com/products-and-services/save-energy-and-money/time-of-use-program>

²³⁷ Both NEM 1.0 and NEM 2.0 customers have a 20-year legacy period under each respective structure. However, all NEM customers must take service on an applicable rate which may change over time.

²³⁸ See Smart Rate Design for a Smart Future (July 2015), Regulatory Assistance Project: <https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/>

Some segmentation of traditional rate classes may be warranted. Technology-specific rate classes are rarely a good idea, but the residential rate class could be segmented into a “simple” subclass and an “advanced” subclass. Larger users and distributed generation customers could be required to be in the advanced subclass with more complex rates. Smaller users and low-income customers could be placed into the simple subclass, where the rate reforms are more gradual and have less customer risk, such as a peak-time rebate instead of critical peak pricing. This type of segmentation may allow for faster progress towards more complex rate structures by addressing key concerns about technology discrimination and bill impacts on vulnerable customers.

Granular Value-based Export Credit Structures for Larger DER Projects

For larger DER facilities, such as on-site projects for C&I customers, community solar or a broader remote net metering program, California could consider an export credit structure like the NY value of distributed energy resources (VDER) tariff:

- Hourly energy pricing based on wholesale markets;
- Time-based credits for avoided capacity costs (generation and delivery); and
- An environmental value for zero- and low-emissions generation technologies.

Such a pricing scheme addresses directly concerns about cost shifting by aligning export compensation explicitly with value. The NY VDER tariff also includes locational distinctions for many of its elements. Of course, this pricing can be integrated with broader policy efforts. The original VDER tariff included a **“market transition credit”** for community solar projects that provided a step down over time between the previous policy framework and the VDER tariff. This market transition credit has since been replaced with a “community credit” for certain categories of projects.

Two-way kWh Charge for DER Customers with Load

The above concepts provide a pathway towards more efficient and equitable pricing for the vast majority of electric system costs, short-run marginal energy costs, environmental externalities as well as long-run marginal capacity costs for generation, transmission and distribution. However, this does not address administrative and general costs, or potentially other categories of residual costs. Famously, Bonbright noted that there are no fixed principles for allocating and charging these costs and the debate is typically left to other related policy concerns.²³⁹ One potential category of residual costs could be the backbone of the distribution network, which was originally built to deliver energy to customers from the centralized grid, but now the distribution backbone must be built and maintained to handle two-way flow of energy.

While some utilities and consultants argue that these costs should be recovered through customer charges or demand charges, those methods typically have significant downsides, including bill impacts on small users,

²³⁹ Bonbright, James C. (1961), *Principles of Public Utility Rates*, Columbia University Press, at p. 348: <https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/>

insufficient linkage to marginal costs, and the inability of customers to understand and manage their bills. In some circumstances, those downsides can be mitigated if the charges are designed and limited appropriately. A more efficient and equitable option could be a two-way kWh charge on both imports and exports, spreading these costs over a larger billing determinant in a non-discriminatory manner.²⁴⁰ This new billing determinant corresponds directly to a broader conception of how DG customers use the grid, as well as a reasonable metric of the “size” of a customer. Another key feature of this concept is that it avoids undue discrimination because the *rate* is the same across all customers within the class, and the reform is that it applies both to imports and exports. Close attention should be paid so that only certain categories of costs are included in this rate.

²⁴⁰ See Designing Distributed Generation Tariffs Well (Nov. 2013), Regulatory Assistance Project: <https://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well/>