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

FEBRUARY 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

Contributors:
Bridget Sieren-Smith
Ankit Jain
Alireza Eshraghi
Simon Hurd
Julia Ende
Josh Huneycutt

Special thanks to:
Nathan Barcic, Franz Cheng, Dorothy Duda, Beth LaCour, Paul Phillips, Jean Spencer, Elaine Sison-Lebrilla, Erica Petrofsky, Christopher Westling, Ari Gold-Parker (E3), Mark LeBel (Regulatory Assistance Project), David Roland-Holst (UC Berkeley)

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 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.[2] This report (the SB 695 Report or White Paper) lays the foundation for an "En Banc Meeting on Cost and Rate Trends" to be held on February 24, 2021, which will provide 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 and sustaining affordable rates 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 in the CPUC's SB 695 Report and the desire to bring their relative impacts on summary rate forecasts into sharper focus within the mammoth operations and revenue requirements of California's IOUs. The figures below

[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."

[2] Natural gas trends or projections are part of the Residential Energy Cost Calculator forecasting inputs, but this paper will not cover load management standards such as demand response and advanced rate design.

provide the illustrative impacts of projected wildfire spending relative to the other major bundled[3] residential rate components from 2021 through 2030.[4]

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

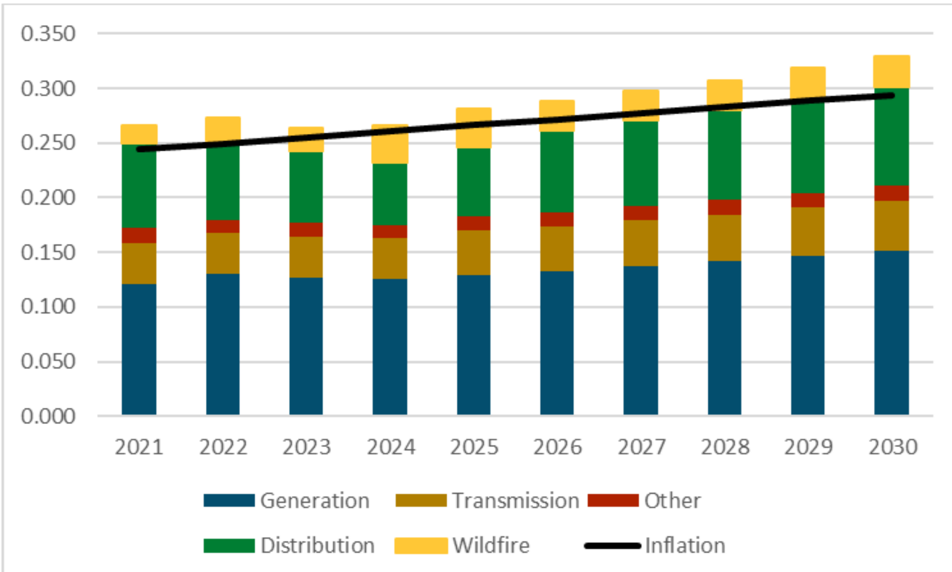
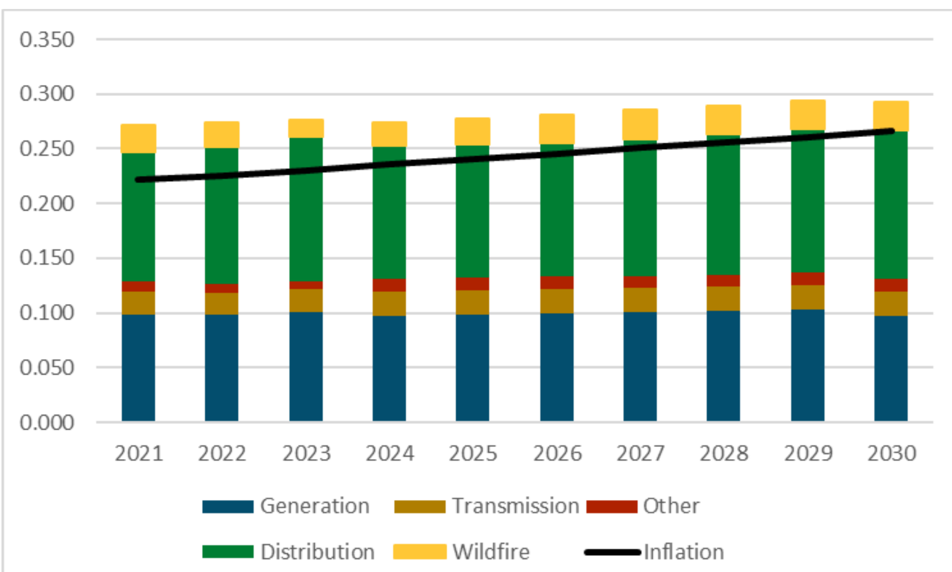


Figure ES-2: SCE Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



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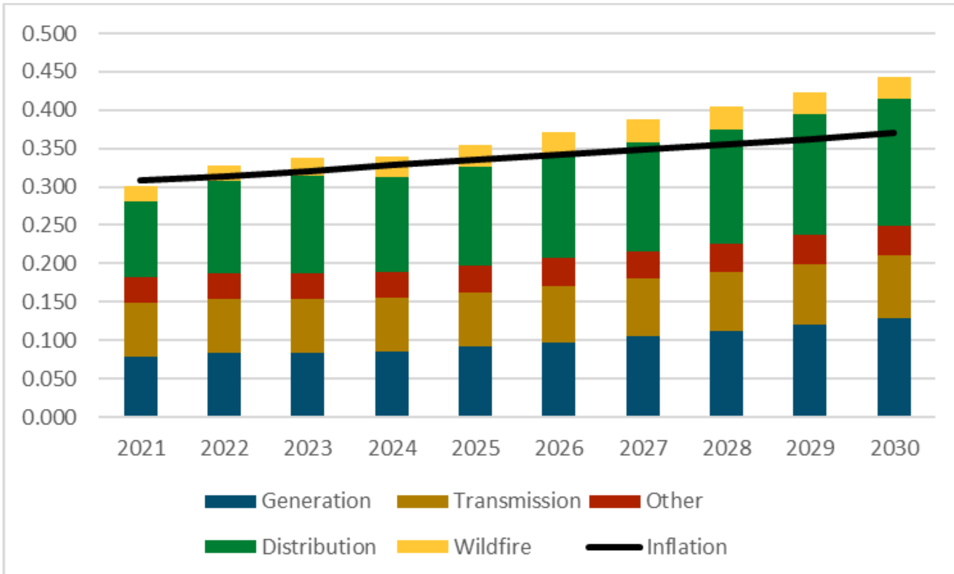
[3] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

[4] 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

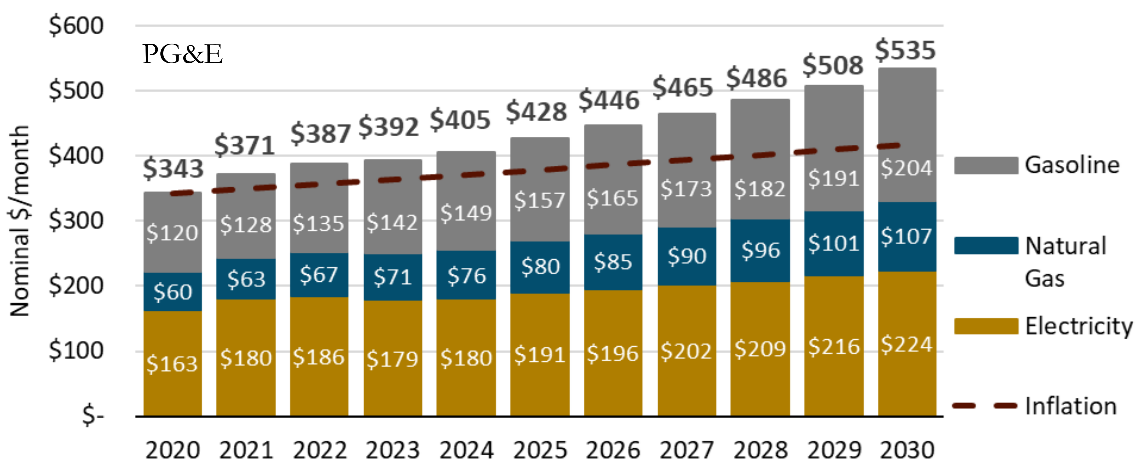


Figure ES-5: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SCE/SoCalGas Rates

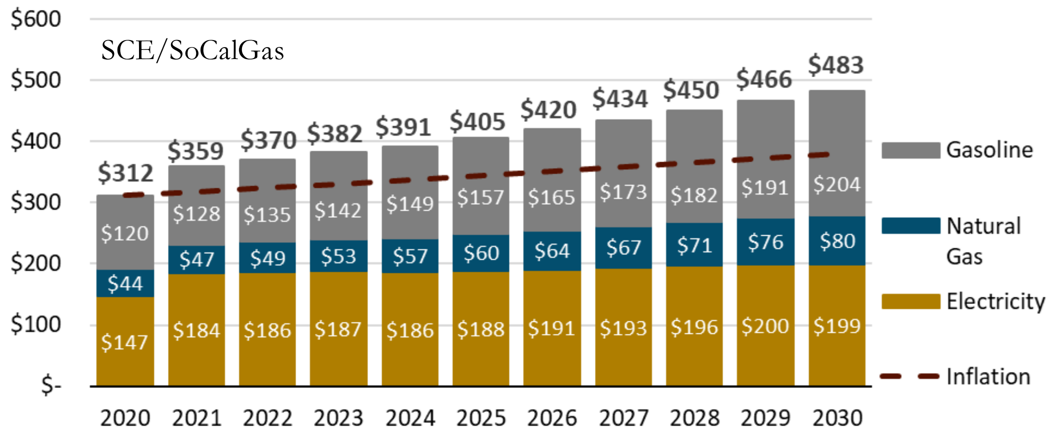
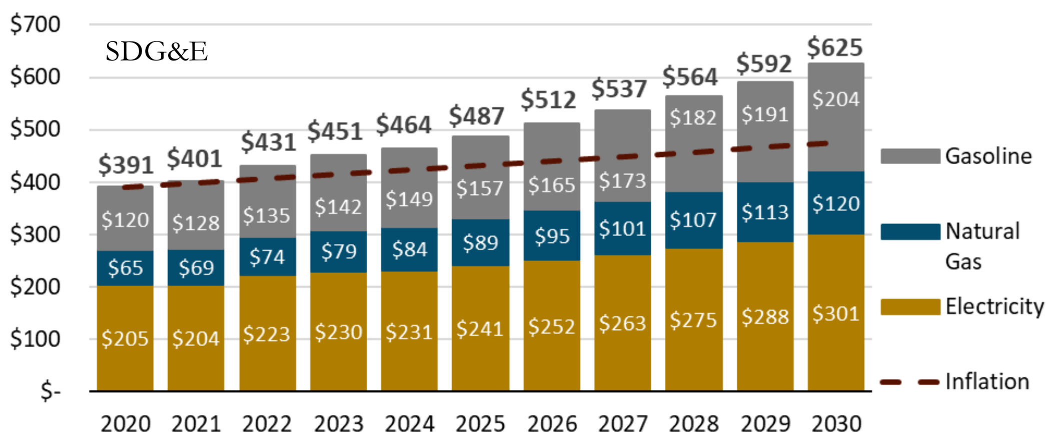


Figure ES-6: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SDG&E Rates



The policy goals and regulatory requirements that create upward cost pressures appear manageable over a longer time horizon, but if not managed correctly 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 that follow, which often results in a cost shift toward the 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.

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.

These trends are interrelated, and while they may not represent novel policy challenges when considered individually, together they pose the risk of greater inequity in their rapid convergence in an increasingly competitive and innovative energy landscape.

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.[5] 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.

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

[5] 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.

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.

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.[6] 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.

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[6] 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 operations[7] 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 categorically[8] form part of historical General Rate Case (GRC) costs or stand-alone[9] program costs.

For the 2021 SB 695 Report contained within this white paper, transportation electrification and wildfire-related costs are highlighted as potential cost drivers.[10] 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 bundled[11] 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,[12] 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.[13]

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

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[7] Functional areas of utility operations include generation, distribution, etc.

[8] 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).

[9] 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.

[10] 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 may that place upward pressure on rates and bills.

[11] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

[12] 2019 is the most recent year for which national-level data is available.

[13] 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.[14] 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.[15]

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.[16]

- 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.[17]

- 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.[18]

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

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

16 *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).

17 *Id.*

18 *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.[19]

- 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.[20]

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.[21] Table 1 shows for 2018 and 2019[22] 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

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[19] *See* U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates.

[20] *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

[21] "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.

[22] 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.[23]

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 bundled[24] customer revenue requirement expected to be recouped through authorized forecasted sales to bundled customers.

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

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.

[23] 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.

[24] 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

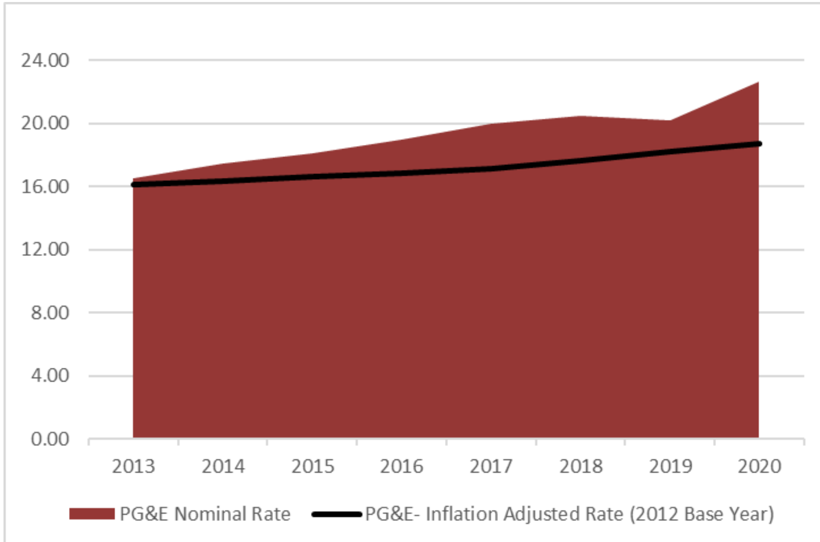


Figure 2: SCE Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

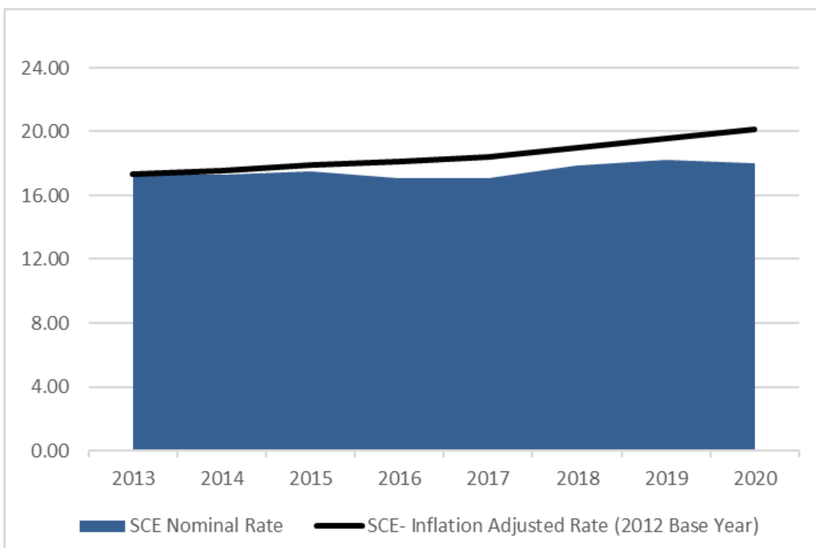
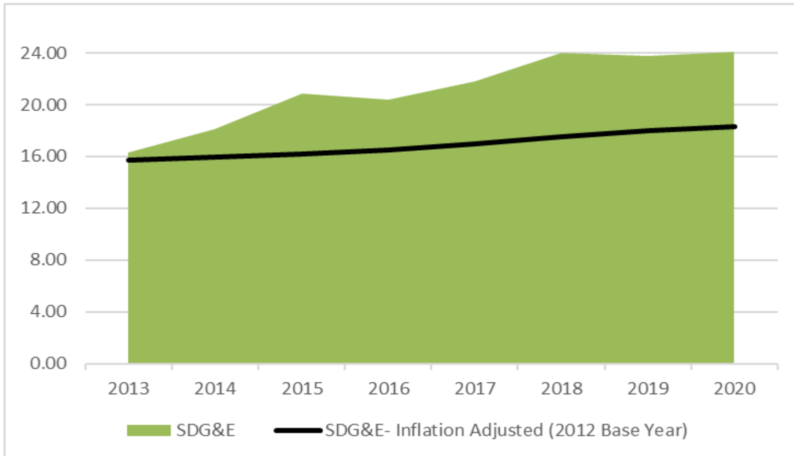


Figure 3: SDG&E Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1



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

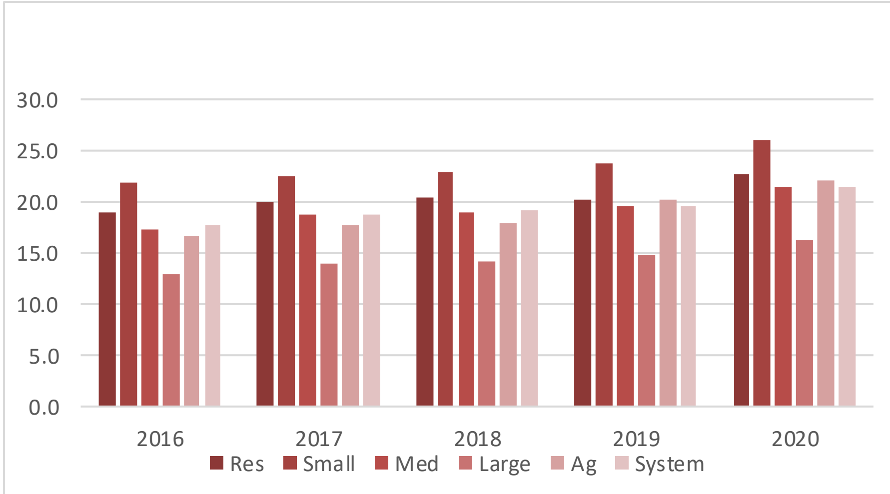


Figure 5: SCE Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1

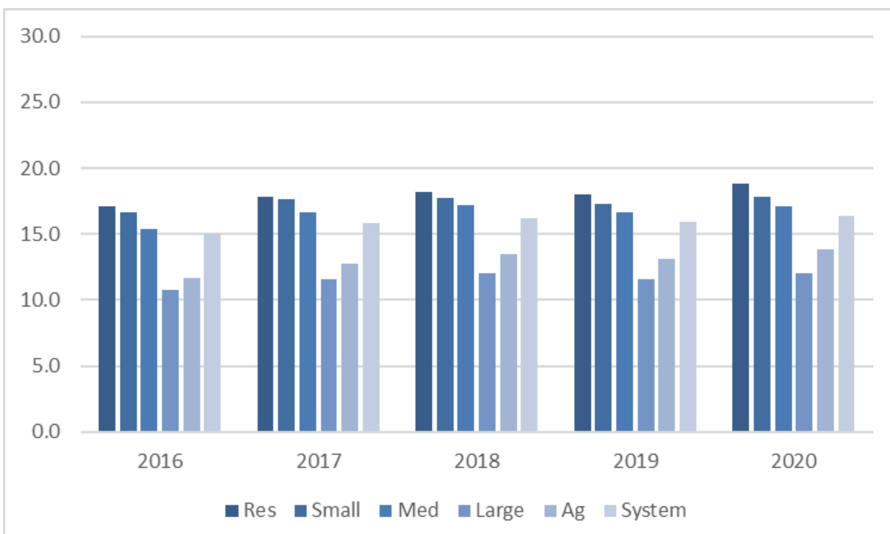
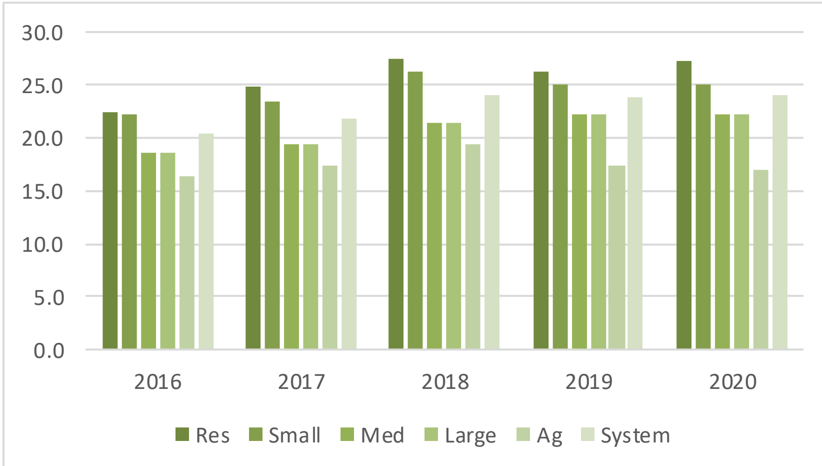


Figure 6: SDG&E Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1



Residential and Select Small Commercial Bundled Average Monthly Bills

The major determinant in calculating bills is electricity **usage**.[25] Residential usage tends to cluster around typical usage profiles, which vary by climate zone.[26] However, typical load profiles for non-residential customers can vary substantially, depending on their usage patterns in the commercial, industrial, or agricultural customer class.[27] 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.[28] Figure 7 through Figure 9 show for each IOU typical bundled average monthly bills for residential customers[29] 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).[30] Bundled small business customers with industry subsector code Food Services (NAICS 722) show typical average monthly bills in the mid- to high triple-digits.[31]

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[25] 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.

[26] 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.

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

[28] 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.

[29] 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.

[30] *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.

[31] 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

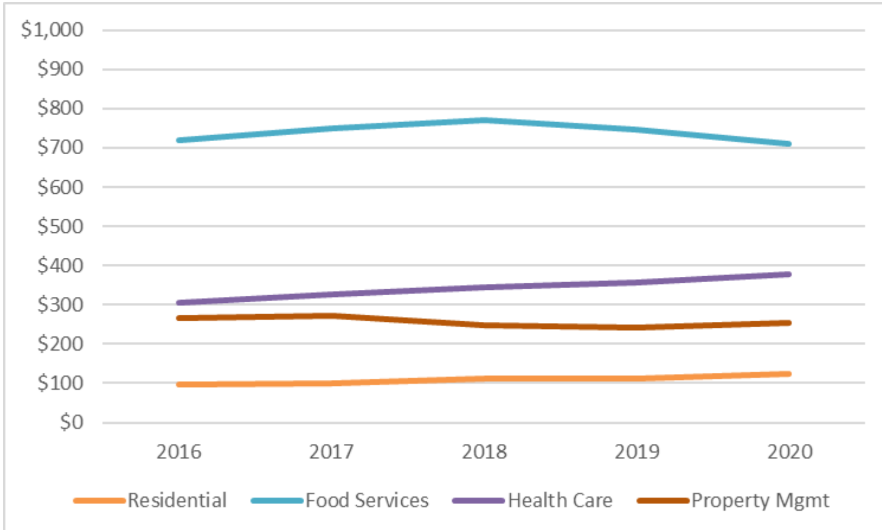


Figure 8: SCE Typical Bundled Average Monthly Bills ($/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1

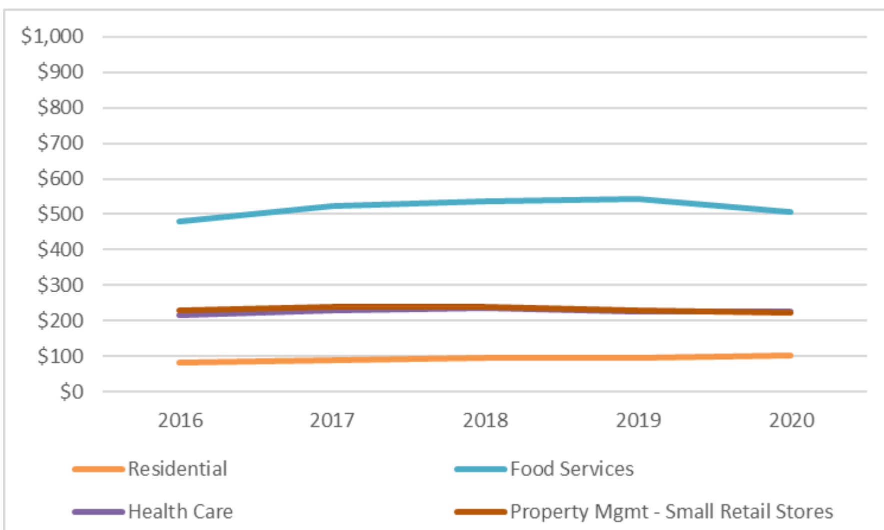
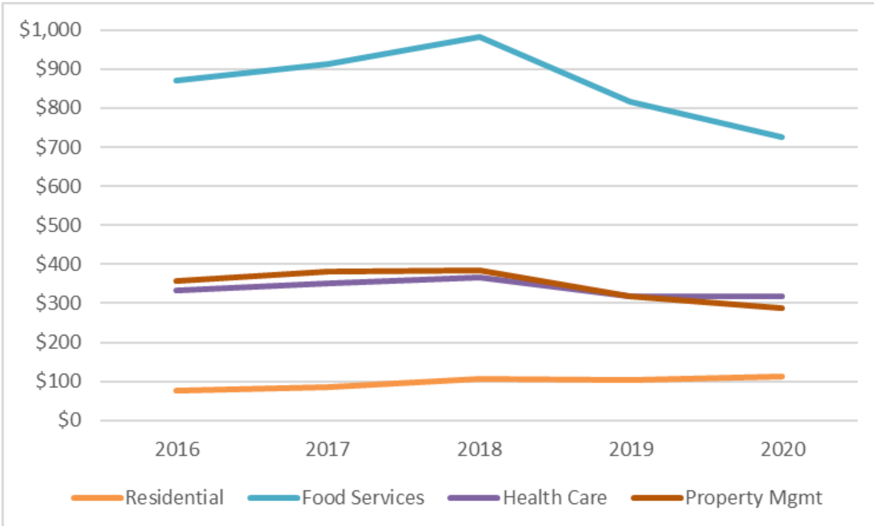


Figure 9: SDG&E Typical Bundled Average Monthly Bills ($/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1



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.[32] 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.

[32] 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 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.

Rate Base = Net capital additions – Accumulated depreciation

Thus, rate base is the amount that remains after accumulated depreciation 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:

Net capital additions > Accumulated depreciation = 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**:

Capital-related revenue requirement = Depreciation expense (including related tax effects) revenue requirement + 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**:

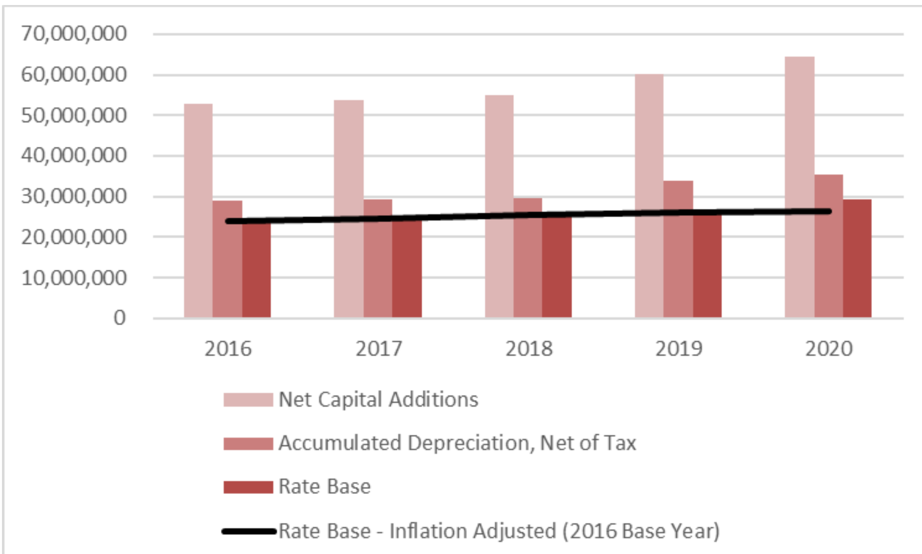
Return on rate base revenue requirement = Authorized rate of return (a percentage) x Rate base

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

Rate Base is Increasing

Figure 10 through Figure 12[34] show the total annual rate base for each of the IOUs from 2016 through 2020.[35] 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.[36]

Figure 10: PG&E, Total Electric Rate Base ($000), Nominal and Inflation-Adjusted, January 1



[34] 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.

[35] "Other" rate base (working capital, other non-fixed asset adjustments) not material and not included.

[36] Percentages in nominal terms. Real terms would be slightly lower to account for inflation.

Figure 11: SCE, Total Electric Rate Base ($000), Nominal and Inflation-Adjusted, January 1

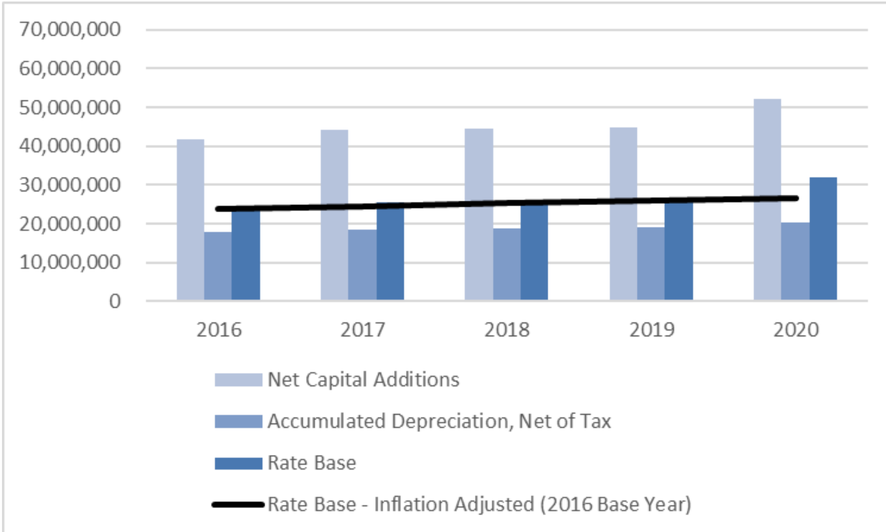
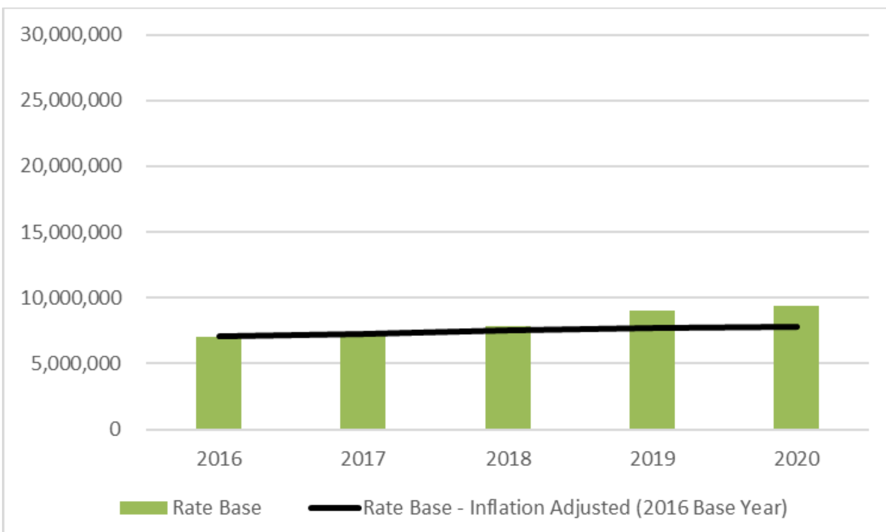


Figure 12: SDG&E, Total Electric Rate Base ($000), Nominal and Inflation-Adjusted, January 1



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-service[37] data net of accumulated depreciation.[38]

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

[38] Accumulated amortization and depletion is reported along with accumulated depreciation.

The net utility plant data is not directly comparable with the IOU rate base data presented above.[39] 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 13 shows 2016 - 2019[40] 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.[41] In other words, Florida Power & Light had the highest bundled retail revenue and is ranked #1, with SCE at #2. Figure 14 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.

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[39] PG&E, SCE, and SDG&E rate base data in Figures 10, 11, and 12 were provided to Energy Division by data request. This data is based on rate base over which return on rate base as of Jan 1 each year is calculated. It is unknown what methodology the IOUs use for reporting plant-in-service and accumulated depreciation data to FERC.

[40] 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).

[41] 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 13: Net Electric Utility Plant, PG&E, SCE, and Five Other U.S. IOUs ($000), Ranked by Bundled Revenue (Highest to Lowest) (2016 – 2019)

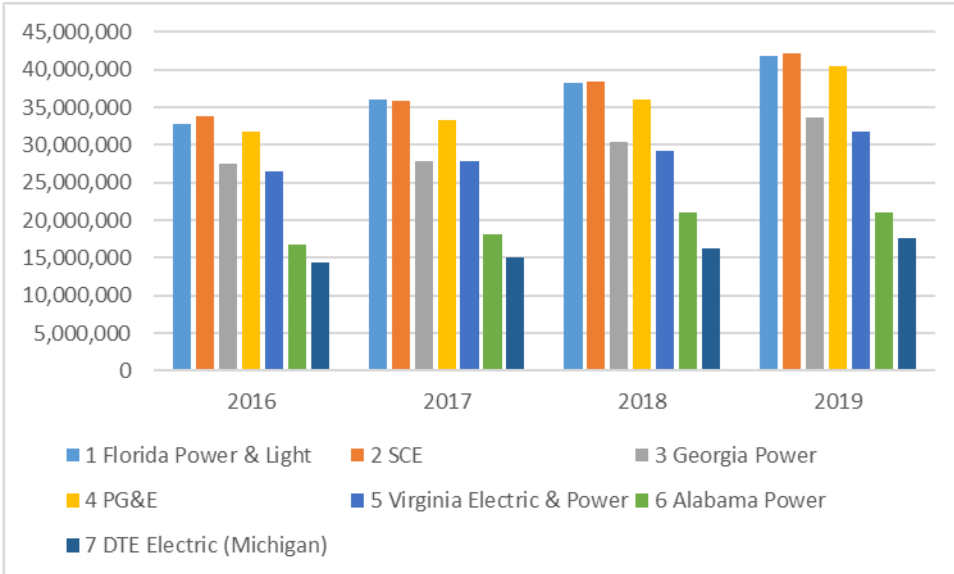
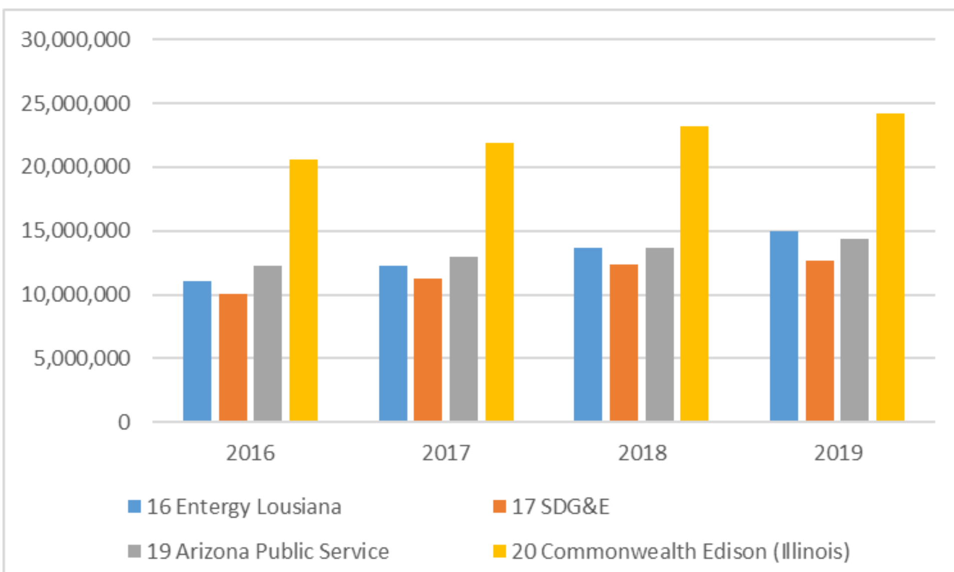


Figure 14: Net Electric Utility Plant, SDG&E and Three Other U.S. IOUs ($000), Ranked by Bundled Revenue (Highest to Lowest) (2016 – 2019)



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,[42] 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.[43] Return on rate base may represent a return to shareholders paid by ratepayers; however, having a set[44] 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.[45]

Figure 15 through Figure 17[46] 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.[47] 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.

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

[43] Profit is earned after the service of debt acquired to finance capital additions.

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

[45] 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.

[46] 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.

[47] 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 15: PG&E, Return on Electric Rate Base Revenue Requirement ($000), Nominal Rates in Effect January 1

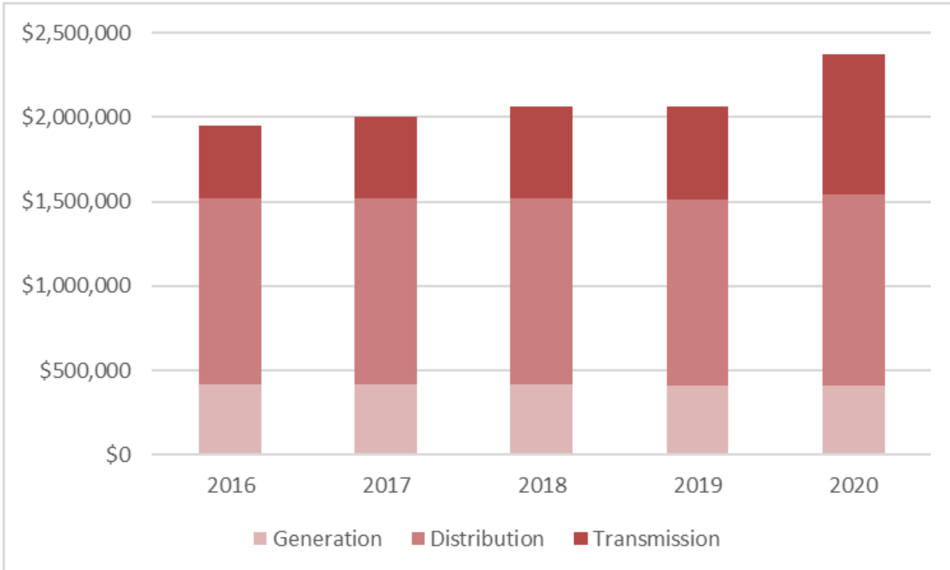


Figure 16: SCE, Return on Rate Electric Base Revenue Requirement ($000), Nominal Rates in Effect January 1

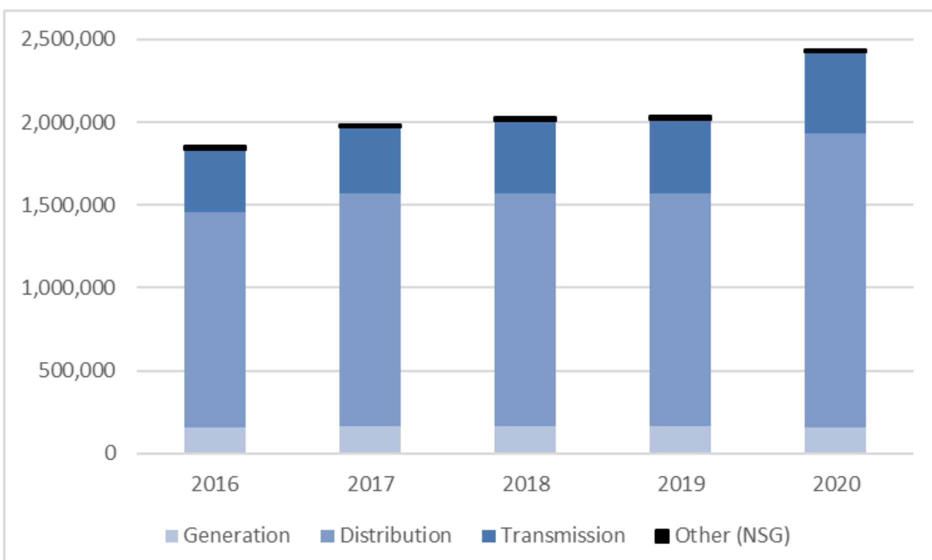
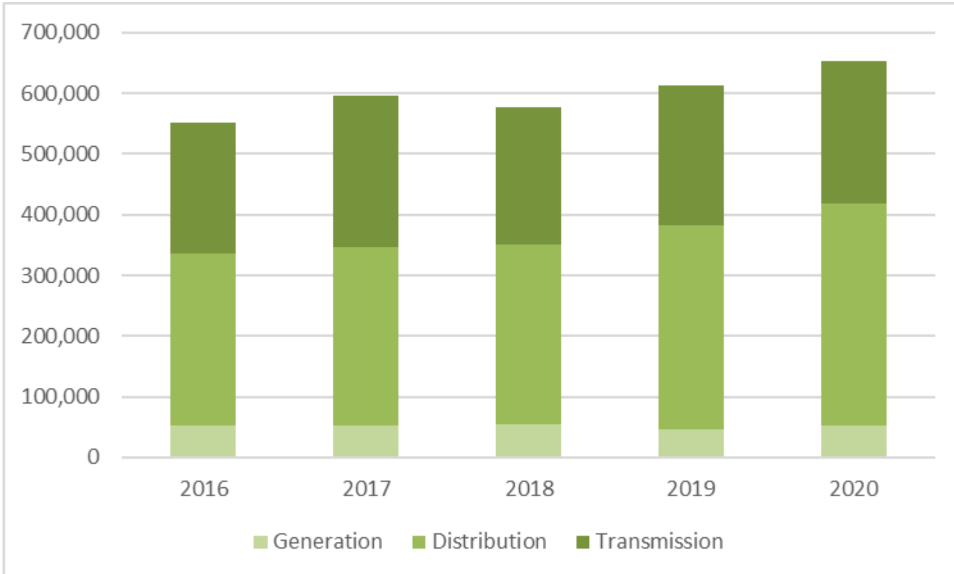


Figure 17: SDG&E, Return on Electric Rate Base Revenue Requirement (no Transmission Data) ($000), Nominal Rates in Effect January 1



IOU net capital additions, accumulated depreciation, rate base, depreciation expense (including related tax effects) revenue requirement, and return on rate base requirement are reviewed in Phase I of each General Rate Case (GRC) cycle,[48] 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.[49] After program termination, the ongoing capital-related revenue requirements will become part of GRC filings.[50] It is unknown at this time if these ongoing capital-related revenue requirements will be tracked separately in GRC filings.

[48] 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.

[49] 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.

[50] 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).16-01-044[51] 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.[52] 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.[53] The CPUC directed this study to gather information in preparation for its planned revisit of the tariff.[54] 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

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

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

[53] 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.

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

energy generation. Table 2 shows the TRC and RIM weighted average benefit-cost ratios for the residential customer sector and all sectors.

Table 2: 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.[55] Potential equity concerns related to the NEM cost shift include the following:[56]

- 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.

[55] 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.

[56] 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).[57] 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.[58] 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.[59]

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 EVs[60] on a case-by-

[57] 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.

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

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

[60] 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.

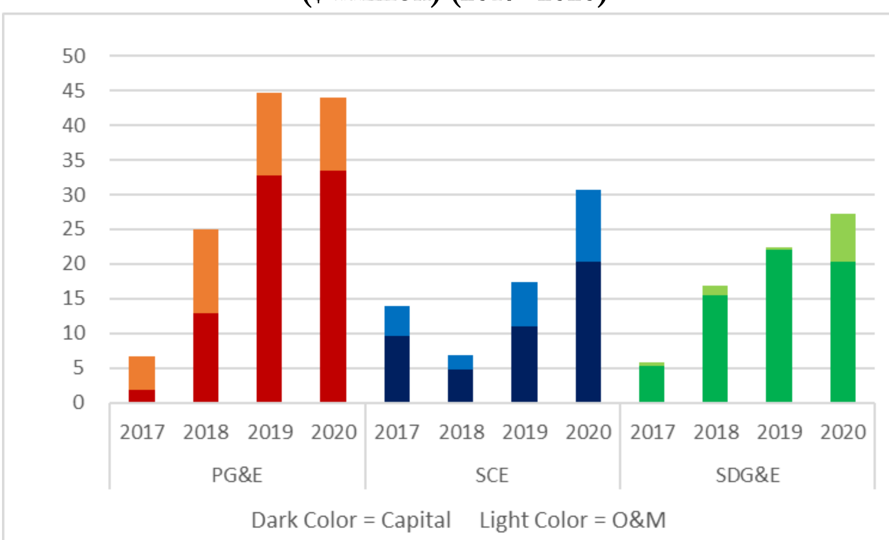
Costs in Rates

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.[61]

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

Figure 18 shows each IOU's transportation electrification program spending by O&M and capital cost classification and by the year implemented in rates.

Figure 18: PGE, SCE, and SDG&E Transportation Electrification Program Costs in Rates ($ million) (2017 -2020)



[61] *See* "Transportation Electrification Investments" on CPUC website: https://www.cpuc.ca.gov/zev/ .

Table 3 shows the rate attributable to transportation electrification costs embedded in the bundled average residential rate for the period 2017 to 2020.[62]

Table 3: 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

[62] 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.[63] 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.[64]

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 meet 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

63 *See* each IOU's WMP at https://www.cpuc.ca.gov/2019wmp/ .

64 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 4 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.[65]

Table 4: 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 19 and Figure 20 show O&M and capital costs incurred[66] 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.[67]

[65] FERC-related costs are not included in SDG&E's filed WMPs.

[66] Costs may be implemented in rates in a different year than year incurred.

[67] Other wildfire prevention costs represented include FERC-jurisdictional and mixed CPUC GRC and FERC Common costs.

Figure 19: SDG&E Wildfire Prevention O&M Costs Relative to All Other O&M Costs (Non-Wildfire), ($ million)

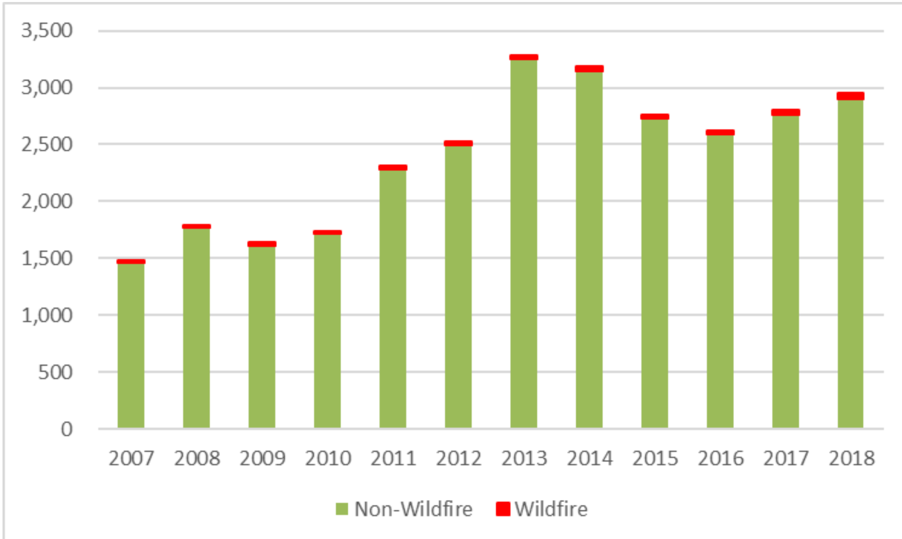


Figure 20: SDG&E Wildfire Prevention Capital Costs Relative to All Other Capital Costs (Non-Wildfire), ($ million)

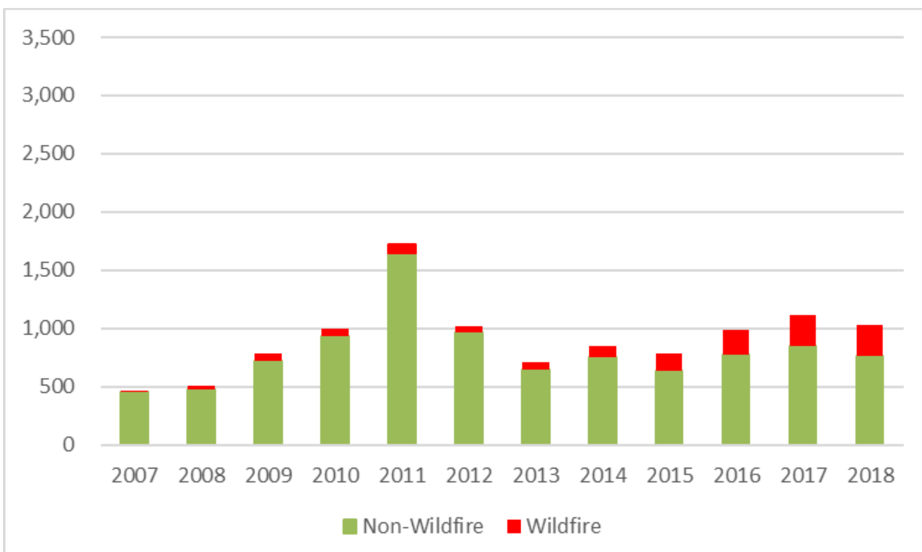


Figure 20 shows SDG&E's wildfire prevention capital expenditures increasing over time, particularly after 2013. Table 5 shows this wildfire prevention capital spend by SDG&E-designated cost categories for the years 2016 to 2018.

Table 5: 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 19 and Figure 20 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 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.[68]

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 6 through Table 9 show this data.

Table 6 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 6: 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 7.

Table 7: 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 8 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.

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

Table 8: 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 9.

Table 9: 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.[69]

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 10 shows the in-service date of the largest transmission projects over the past 10 years. For two of the three projects in Table 10, the final total costs

[69] 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 10: 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,[70] which provided incentives pursuant to Section 219 of the Federal Power Act[71] 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.[72] However, at this time, the cost of the project has nearly doubled, with over $3.06 billion placed into rate base.[73] It appears that SCE will seek the incentive ROE on the total project cost of $3.06 billion.

Increase in Utility Self-Approved Projects

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

[71] 16 U.S. Code § 824s - Transmission infrastructure investment

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

[73] 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 11 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 10 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.

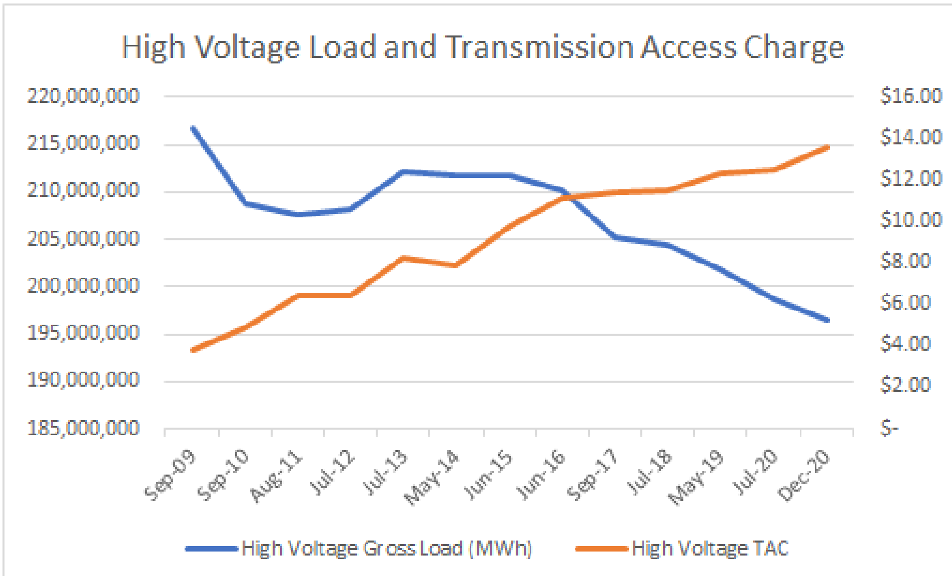
Table 11: CAISO-approved and Utility Self-approved Projects 2010-2019 ($000)

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).[74] Figure 21 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.[75]

Figure 21: 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 12, 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.[76] 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.[77]

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[74] 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.

[75] 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).

[76] 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).

[77] *See Costs and Cost Savings for the RPS Program* (Padilla Repot) at: https://www.cpuc.ca.gov/General.aspx?id=6442463728 .

Table 12: 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[78]	$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[79]	$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

[78] RPS revenue requirements do not distinguish the above-market portion.

[79] Demand Response includes DR Auction Mechanism and IDSM, as applicable.

SB 1, AB 217, AB 2723	California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	$40	$121	$11	$172
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[80]	$76	$33	$22	$131
SB 1, AB X1 15	New Solar Homes Partnership Program	$57	$46	$10	$113
Other	Other[81]	$156	$140	$13	$309
Five-Year Total[82]		**$15,303**	**$16,092**	**$5,660**	**37,055**
One-Year Average Total[83]		**$3,061**	**$3,218**	**$1,132**	**$7,411**

[80] Transportation Electrification includes pilots, as applicable.

[81] 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.

[82] 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.

[83] *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 months[84] 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 bundled[85] 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.[86]

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 13.

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

[85] Bundled IOU customers receive all services from the IOU: generation, transmission, and distribution services.

[86] 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 13: 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 14 shows the wildfire management and transportation electrification portion of monthly forecasted bundled residential customer bills in 2021 and 2030.

Table 14: 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 usage[87] 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.

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

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 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.[88] In addition to producing rates for the affordability metrics, each IOU's CRT is used to produce a short- to medium term comprehensive[89] 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 requirement[90] and forecasted sales information, as provided by the large electric IOUs,[91] 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

[88] D.20-07-032, Ordering Paragraph (OP) 1, p. 99.

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

[90] 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.

[91] CRTs for the large natural gas IOUs are in development.

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.

Bundled Rate Transparency Considerations

As rates and bills produced by the CRT are occasionally shared with parties outside of the CPUC,[92] there have been inquiries into the revenue requirements and sales forecasts that comprise the rates.[93] Forecasted incremental revenue requirements modeled in the CRT are based on publicly available information; there are no transparency issues related to the availability[94] of forecasted revenue requirement data at system level. However, certain sales forecast data provided by the IOUs in their respective CRTs[95] are not available to parties outside the CPUC.

Bundled sales forecast data are available in the public domain for PG&E[96] and are not publicly-available for SCE and SDG&E.[97] 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:

$$Rate = Authorized\ Revenue\ Requirement\ /\ X;\quad X = Authorized\ Revenue\ Requirement\ /\ Rate$$

While not a transparency concern for the CPUC due to the CRT, transparency for stakeholders[98] with respect to the bundled revenue requirement and bundled sales forecast in authorized rates[99] 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 15.

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

[93] Rate = Revenue Requirement / Forecasted Sales.

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

[95] Sales forecast data in the CRT may vary from year to year.

[96] 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.

[97] 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.

[98] 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.

[99] Authorized rates currently in effect. Prior authorized rates may not have these transparency issues.

Table 15: 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,[100] 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.

[100] "Interested parties" could include those in higher-learning institutions as well as in other California state agencies.

3.3 En Banc Bundled Residential Customer Rates Forecast

Background

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.[101] 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.[102]

Methodology and Assumptions

PG&E's, SCE's, and SDG&E's current CRT[103] 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.[104] 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 requirements[105] and sales forecasts.[106]
- 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.[107]
- 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

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[101] The CRTs are not capable of calculating rate or bill impacts for unbundled customers.

[102] *See* Section II, sub-section, "Historical Trends in Electric Rates and Bills," sub-heading *Residential and Select Small Commercial Bundled Average Monthly Bills.*

[103] 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).

[104] Actual rates at yearend 2020 are included as a reference.

[105] 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.

[106] CRT-produced bundled residential sales forecasts are confidential for SCE and SDG&E as indicated in the previous sub-section "Bundled Rate Transparency Considerations."

[107] 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.[108] 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.[109]
- 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 16.[110]

Table 16: 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

[108] 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?docketnumber=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.

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

[110] 2020 actual rate presented for reference. The rates in Table 16 and Figure 22 through Figure 26 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

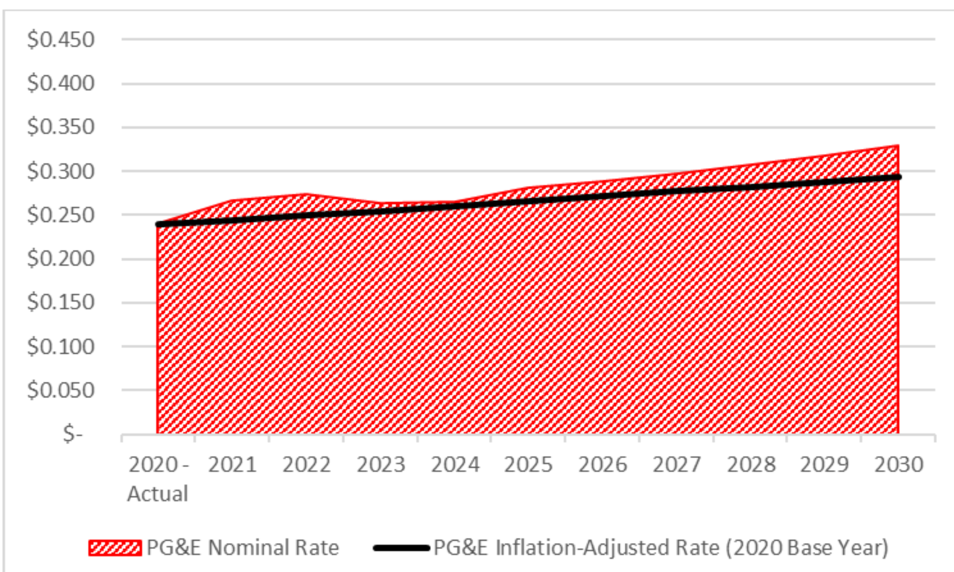
The percentage change in forecasted bundled residential rate for PG&E[111] of 37 percent over 10 years is broken down by the forecasted bundled residential revenue requirement and bundled residential sales forecast changes as shown in Table 17:[112]

Table 17: 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.[113] The En Banc Bundled Residential Rates Forecast baseline scenario with 2020 actual inflation-adjusted forecasted rates are shown in Figure 22 through Figure 24.

Figure 22: PG&E Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario



[111] 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.

[112] 2020 actual rates at year-end.

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

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

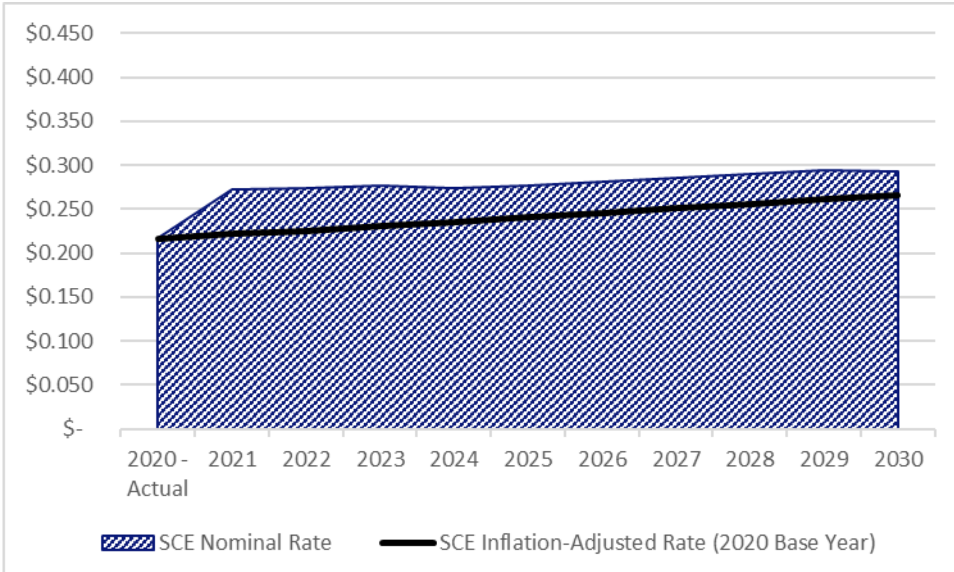
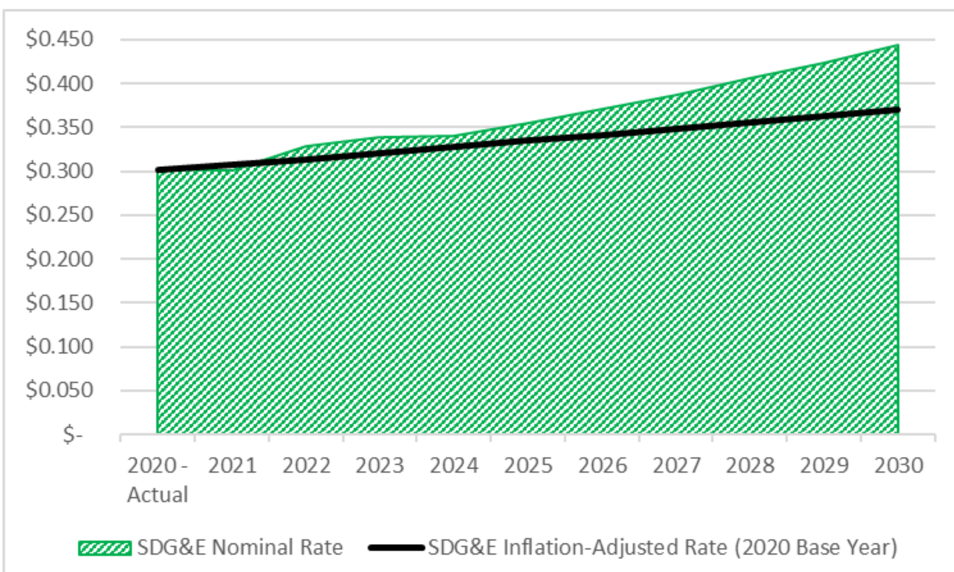


Figure 24: SDG&E Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario



The En Banc Bundled Residential Rates Forecast is shown in nominal dollars per kWh in Figure 25 and deflated to 2019 dollars per kWh i.e., 2019 real dollars,[114] per kWh in Figure 26.

Figure 25: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates (nominal $/kWh), Baseline Scenario

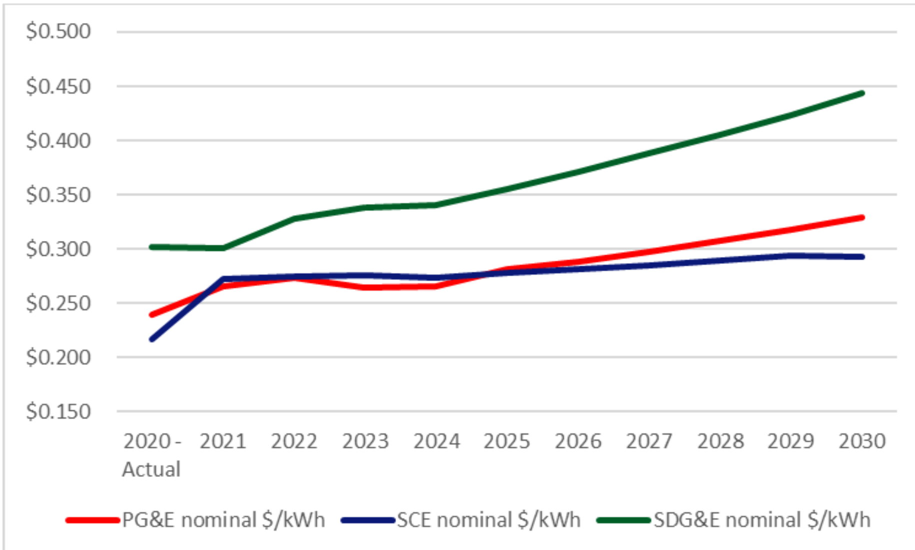
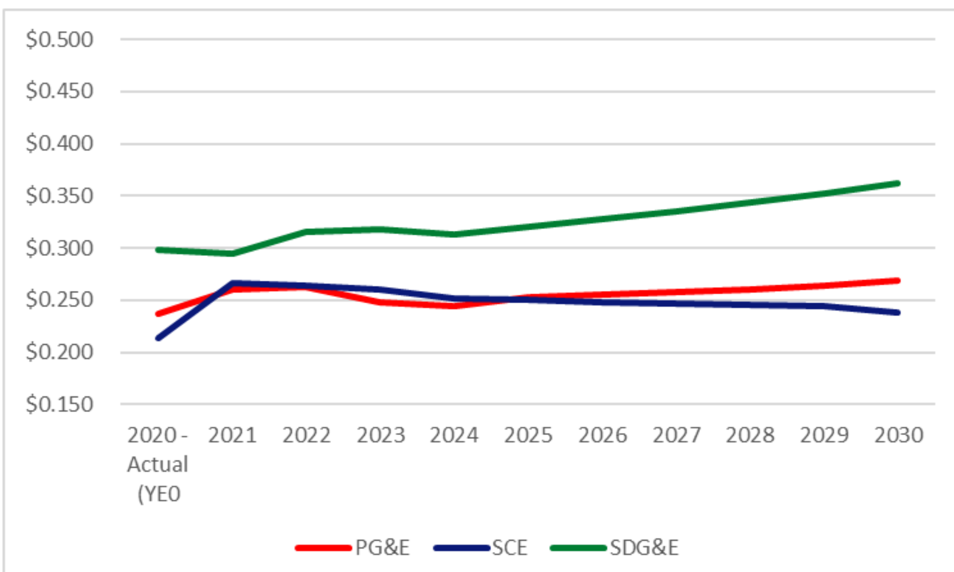


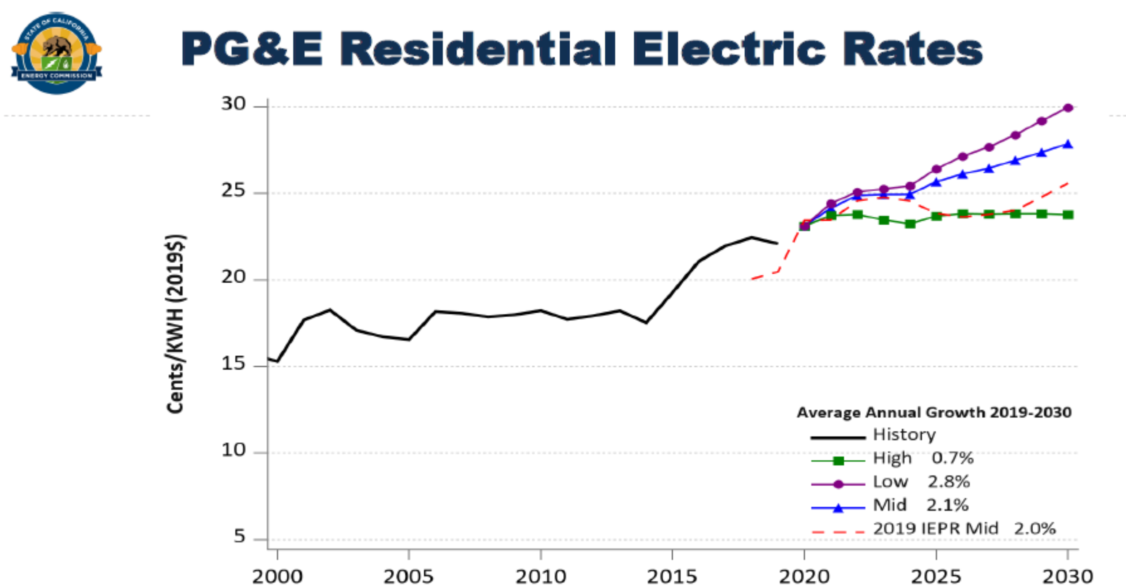
Figure 26: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates ($2019/kWh), Baseline Scenario



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.[115] Planning area rates are the weighted average for all utilities in the planning area, e.g., IOUs and Publicly-Owned Utilities (POU).[116] Figure 27 through Figure 29 show these residential rates in 2019 dollars.[117] The blue line shows the mid-demand case.

Figure 27: CEC 2020 IEPR Residential Rates Scenarios, PG&E



[114] $2019 dollars uses Gross Domestic Product (GDP) deflator used for CEC Planning Area $2019 average rates (Moody's, July 2020).

[115] *See* 20-IEPR-03 docket, "Electric Rate Scenarios" (August 25, 2020) at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03 .

[116] Planning area rates are not directly comparable with IOU service area rates due to the inclusion of revenue requirement of the POUs.

[117] 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 28: CEC 2020 IEPR Residential Rates Scenarios, SCE

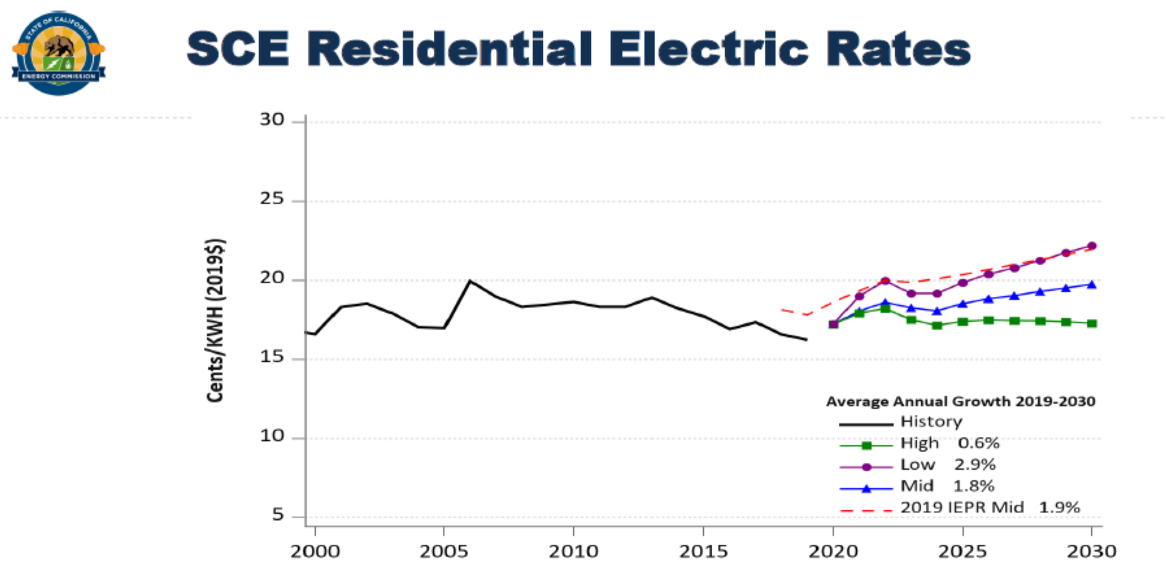
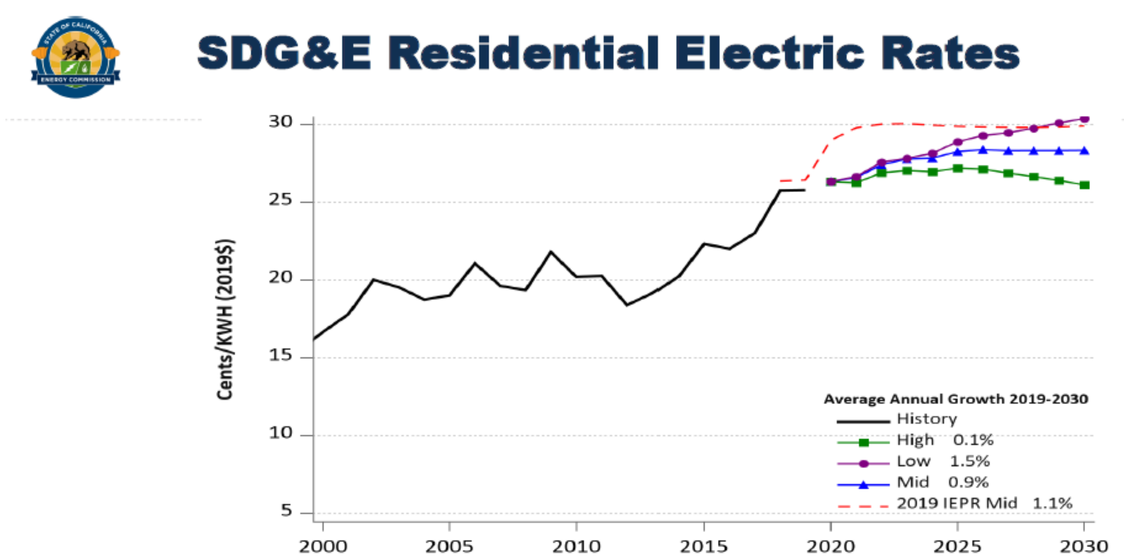


Figure 29: CEC 2020 IEPR Residential Rates Scenarios, SDG&E



The CEC 2020 IPER residential rates planning area forecast uses IOU revenue requirement as originally filed with the CEC for the 2019 IEPR[118] 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.[119]

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

119 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.[120] Table 18 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.[121]

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

[121] The rates in the CPUC Forecasted Bundled Residential Rate column match the 2030 rates in Table 16.

Table 18: 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 19.

Table 19: 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.[122] 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.[123] 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

122 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.

123 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.[124] 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.[125] 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.[126]

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

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[124] 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.

[125] "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.

[126] 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.[127] 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.

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[127] 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 20.

Table 20: 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 21. For convenience, the forecasted baseline bundled residential rate is shown in the upper portion of the figure.[128]

Table 21: 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 22. 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.[129]

[128] The rates in the upper portion of Table 21 match the rates in Table 16. Similar to Table 16, the rates in Table 21 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

[129] 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.

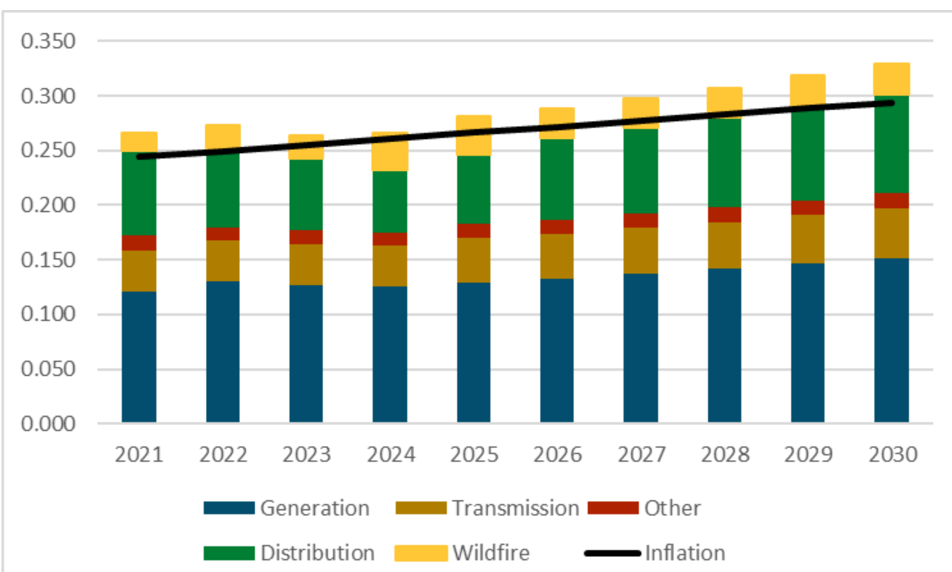
Table 22: Wildfire Portion of Monthly Bill and Total Monthly Bill, Bundled Residential Customers (nominal $/month)

	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;[130] however, it can be viewed separately from the non-wildfire portion of the rate[131] as shown in Figure 30 through Figure 32.[132] The inflation-adjusted forecasted rate line is based on 2020 actual rates. For all embedded rate components by $/kWh, see Appendix B.

Figure 30: PG&E Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



[130] The wildfire rate is included as a component of the distribution rate.

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

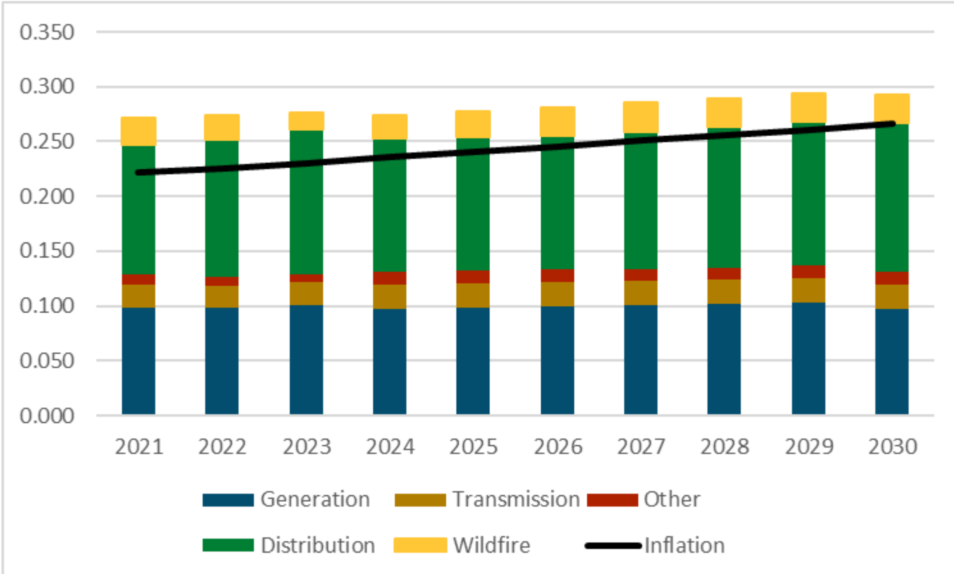
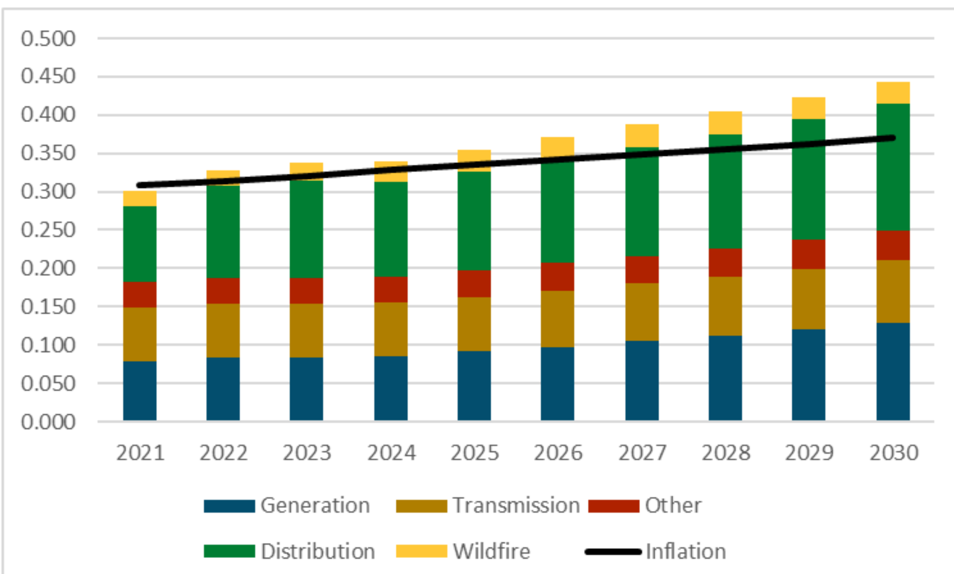


Figure 32: SDG&E Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



Wildfire High-Cost Scenario

[131] The rates in Figure 30 through Figure 32 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

[132] 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: $ 3.9 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.[133] Forecasted revenue requirements in 2030 for estimated wildfire costs at system-level and for bundled residential are show in Table 23.

Table 23: 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 24.[134]

Table 24: 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.

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

134 The rates in Table 24 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.[135] 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

[135] *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.[136] 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.[137]

- **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.[138]

- **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.[139]

[136] 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.

[137] https://calevip.org/about-calevip

[138] http://www.ebudget.ca.gov/budget/2021-22/#/BudgetSummary

[139] 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.[140]
- SDG&E's pending application for Power Your Drive 2.[141]
- 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.[142]
- 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.[143]

Forecasted revenue requirements in 2030 for estimated transportation costs at system-level and for bundled residential are show in Table 25.

Table 25: 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

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

141 *Id.*

142 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."

143 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 26.[144] The baseline TE rate embedded in these total rates is broken out in the lower portion of the Table 26.

Table 26: 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 inserts[145] – 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.[146] 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.

[144] The rates in Table 26 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

[145] 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.

[146] $0.003/kWh x 500 kWh = $1.50/month. The reference 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.

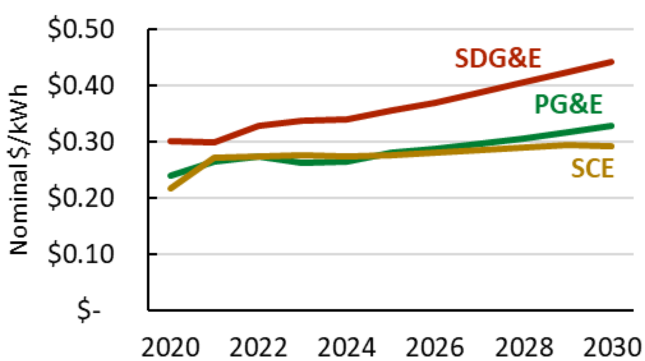
Before presenting the energy bill estimates for a representative household, the underlying forecasts for electric rates, natural gas rates, and gasoline prices are discussed below. These forecasts serve as inputs to the RECC.

Electric and Gas rates and Gasoline Prices

Electric Rates

Figure 33 shows the three large IOU bundled residential average electric rate forecasts prepared by the CPUC Rates team, as described previously.[147]

Figure 33: IOU Bundled Residential Average Electric Rate Forecast



Natural Gas Rates

Figure 34 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.

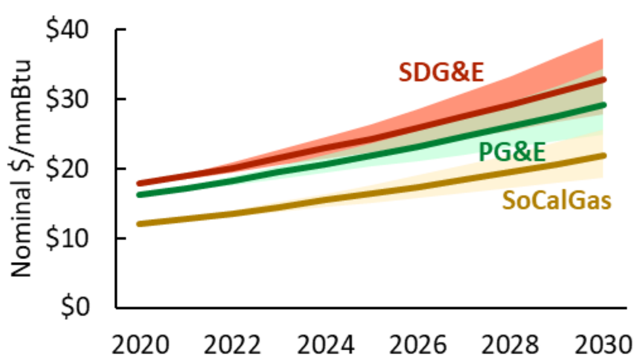
[147] As described in the *3.3 En Banc Bundled Residential Customer Rates Forecast*.

The commodity rate was based on gas commodity price forecasts developed by the gas IOUs and shared in the 2020 California Gas Report.[148] 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.[149] 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 rates[150] and a historical average CA citygate gas price[151]; 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 34: 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 2022[152] (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

[148] 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

[149] See e.g.: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/CPUC%20Rates%20Fact%20Sheet%20SCG.pdf

[150] EIA Sourcekey N3010CA3, https://www.eia.gov/dnav/ng/hist/n3010ca3a.htm

[151] EIA Sourcekey N3050CA3, http://www.eia.gov/dnav/ng/hist/n3050ca3a.htm

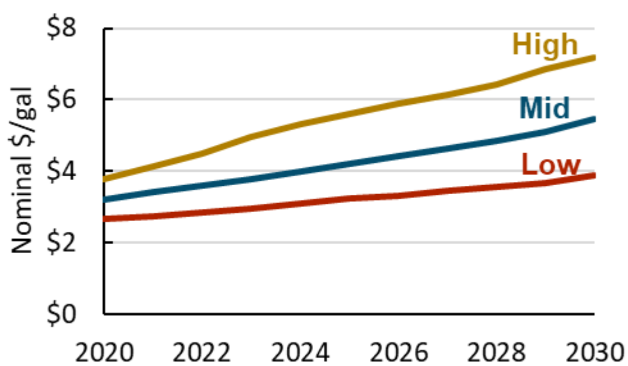
[152] PG&E GRC Phase 1 Settlement, Appendix C.

percent/year[153] 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 2022[154] (gas distribution, transmission, and storage); combined with residential demand falling by 1.1 percent/year[155], 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 35: Gasoline Price Forecast



To provide a more complete picture of household energy expenditures, this analysis also includes gasoline costs for residential households. Figure 35 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.[156] 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.

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[153] 2020 California Gas Report, Table 20: "PG&E Core Throughput."

[154] SoCalGas GRC Phase 1 Proposed Decision, Attachment D.

[155] 2020 California Gas Report, p99.

[156] EIA 2020 AEO, https://www.eia.gov/outlooks/aeo/

The Cap-and-Trade adder is based on the 2019 IEPR GHG Allowance Price forecast.[157] 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 27 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 27: 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 33 and Figure 34, 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

157 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 zone[158] as a representative household with higher-than-average energy costs.

Table 28 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".[159] 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/year[160] – 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 territory[161] – 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 year[162] at 31 miles per gallon.[163]

Table 28: 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

[158] 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

[159] 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

[160] 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

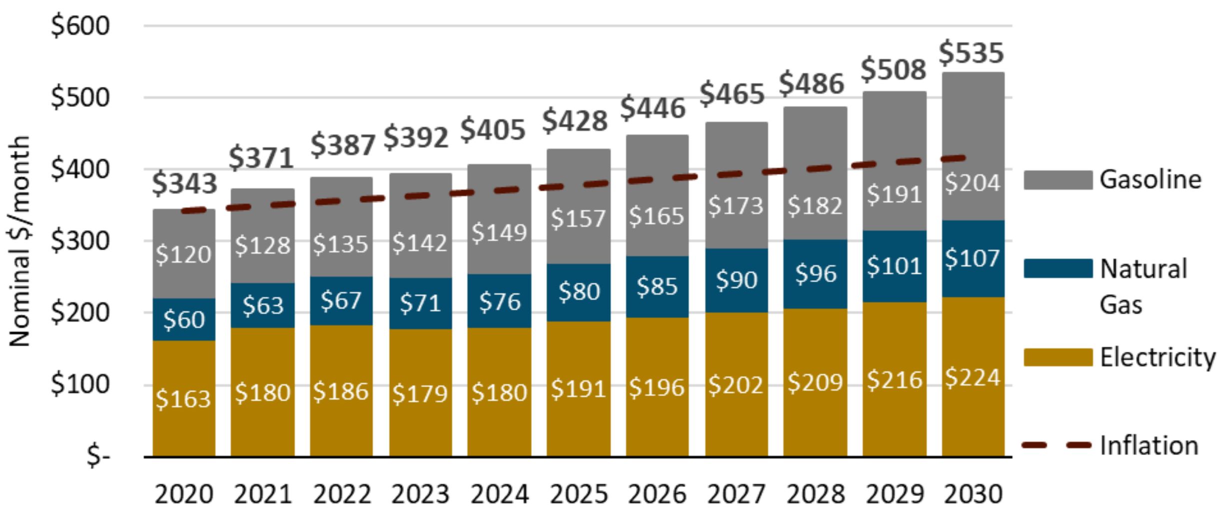
[161] PG&E Average Residential Gas Rate and Bill (January 2021). https://www.pge.com/tariffs/Residential.pdf

[162] California Air Resources Board (2020). https://arb.ca.gov/emfac/

[163] 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.

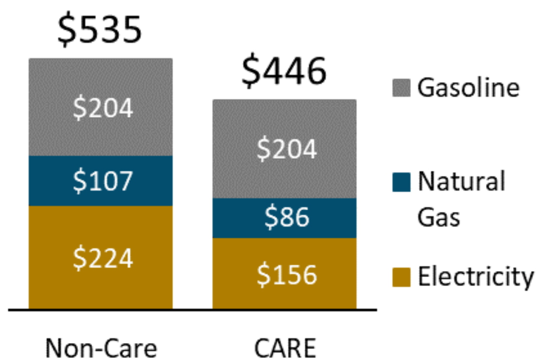
Figure 36: Average Monthly Energy Costs from 2020-2030 for Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E rates



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 36 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 36 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 37: 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 37 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 38: 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

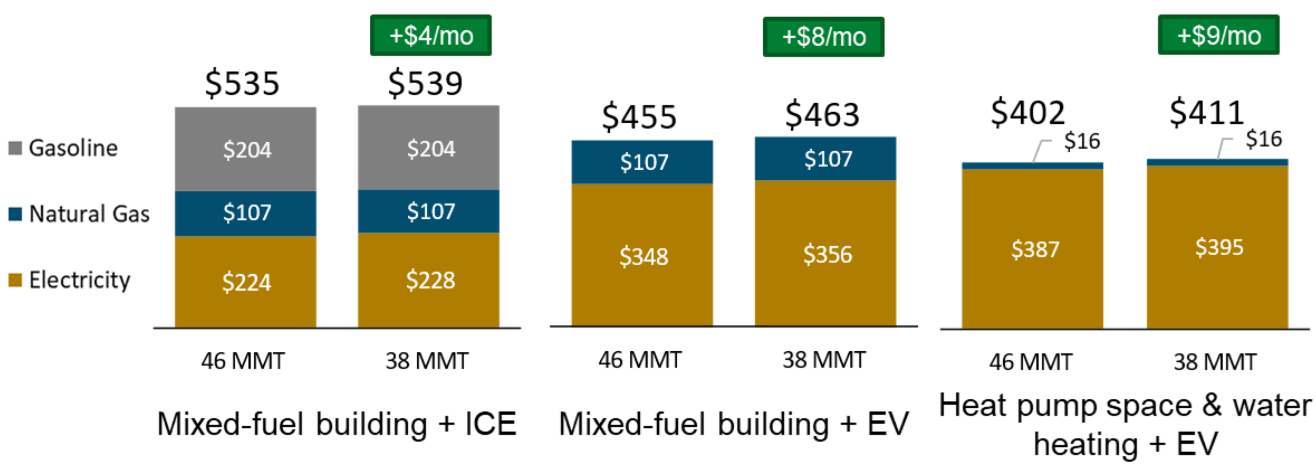


Figure 38 shows the corresponding impact on monthly energy costs for the representative household with above average energy. Two variations on this customer were also considered: a customer in the same mixed-fuel building who drives an EV, and a customer who drives an EV and has undergone "retrofit" 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)[164] 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.[165] 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 39 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 39a), depending on IOU. Customers who do not manage their charging see operating cost savings of $85-$115/month (Figure 39b). 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 39c), and $35-65/month for customers using unmanaged charging (Figure 39d).

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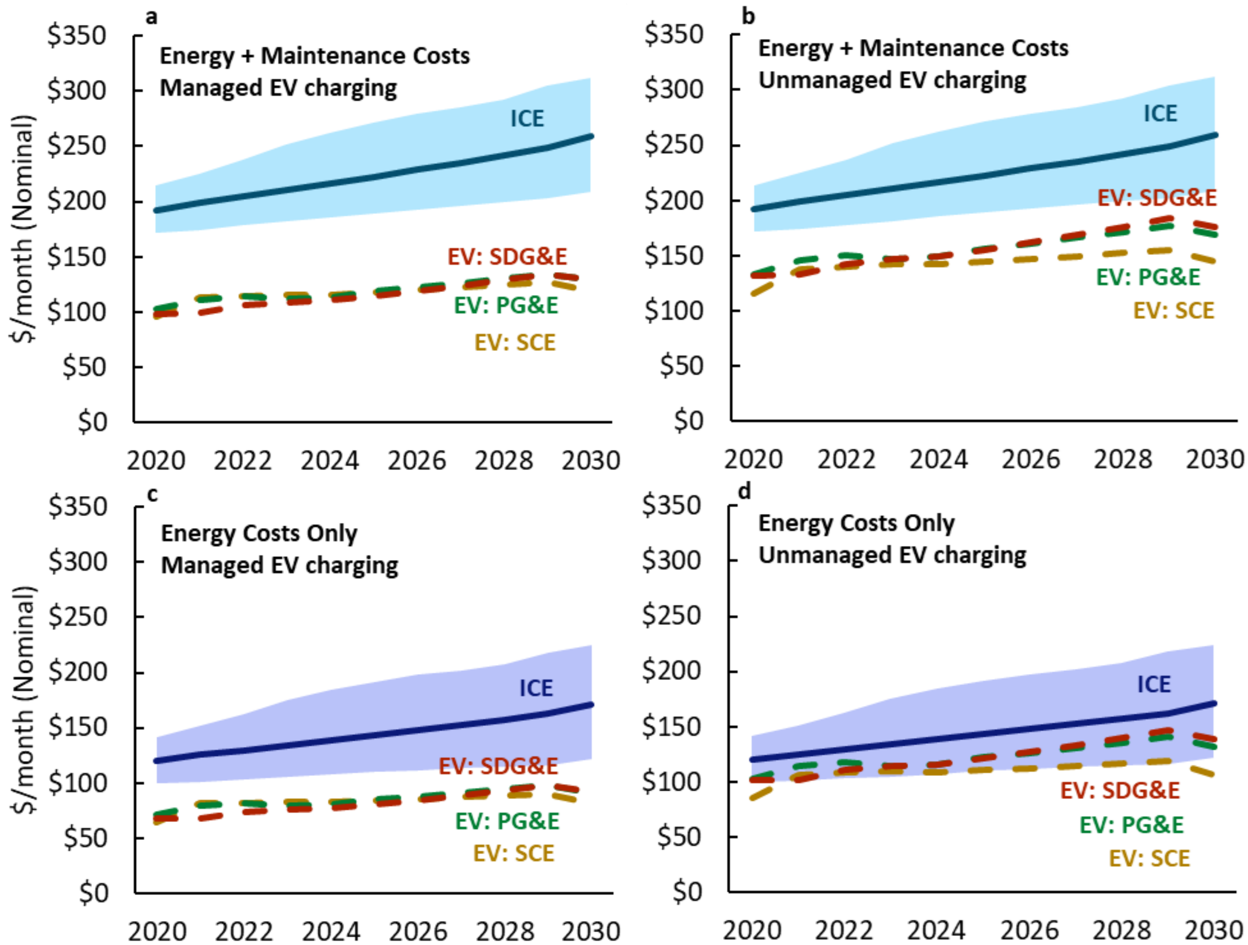
[164] ICCT, "Update of electric vehicle costs in the United State through 2030" (2019). https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf

[165] California Air Resources Board (2020). https://arb.ca.gov/emfac/

Figure 39: 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 39d 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

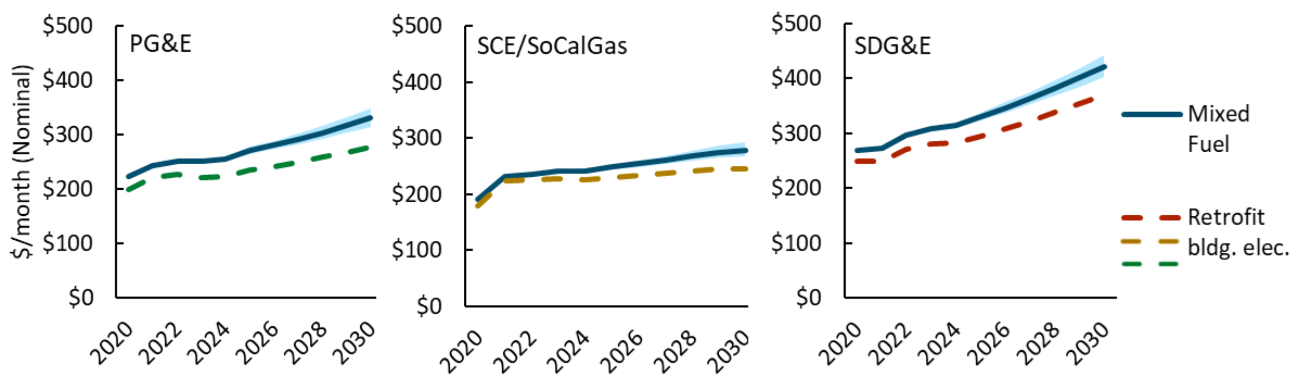
This section considers the impacts of residential building electrification on household energy bills for a representative above average energy usage household in a hot climate zone. While buildings and climate vary across IOU territories, the same household is considered for all three IOUs to isolate 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 40 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.[166] 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).

[166] 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 40: 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

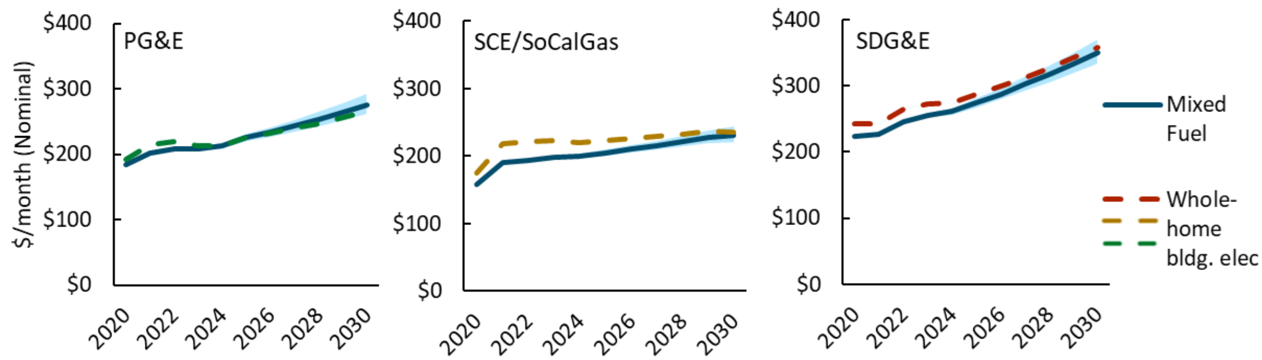


While not considered in this analysis, upfront capital costs may complicate this picture as heat pump space and water heaters may have a higher equipment and/or installation cost than corresponding gas appliances. However, heat pump HVAC units provide both space heating and air conditioning. Thus, the 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 41 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 41: 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.[167,168] 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.

[167] "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

[168] 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 Calculator[169] averaged across IOUs were used, along with 4 percent nominal escalation based on data from the Bureau of Labor Statistics (BLS) Producer Price Index.[170] 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.

[169] 2020 Avoided Cost Calculator, https://www.cpuc.ca.gov/general.aspx?id=5267

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

Table 29: 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 29 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 29.

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 20^{th} percentile income level, meaning that the household's income level is only higher than 20 percent of households in the area, would be an AR_{20} figure. The AR for a household at the 50^{th} percentile of income, meaning a median income household, would be an AR_{50} 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.[171] 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,

[171] 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 Survey[172] found that, during the period December 9th through the 21,st 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.[173]

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 AR_{20} values[174] of at least 35 percent, while the remaining 88.8 percent are in areas with much lower values, as can be seen in Figure 42.[175] 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 42 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.

[172] 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

[173] 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

[174] AR_{20} is the 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.

[175] The plot presents AR_{20} 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 (AR_{50} values) are fairly uniform across the state, as illustrated by Figure 43, which shows the distribution of AR values for 20th and 50th percentile income households across the state. This graph shows that AR_{50} values are relatively low compared to AR values for 20th percentile income households (AR_{20} values), and they are less than 10 percent for the vast majority of the state.

Figure 42: Distribution of Bundled Residential AR_{20} Values by Percent of Households (2019)

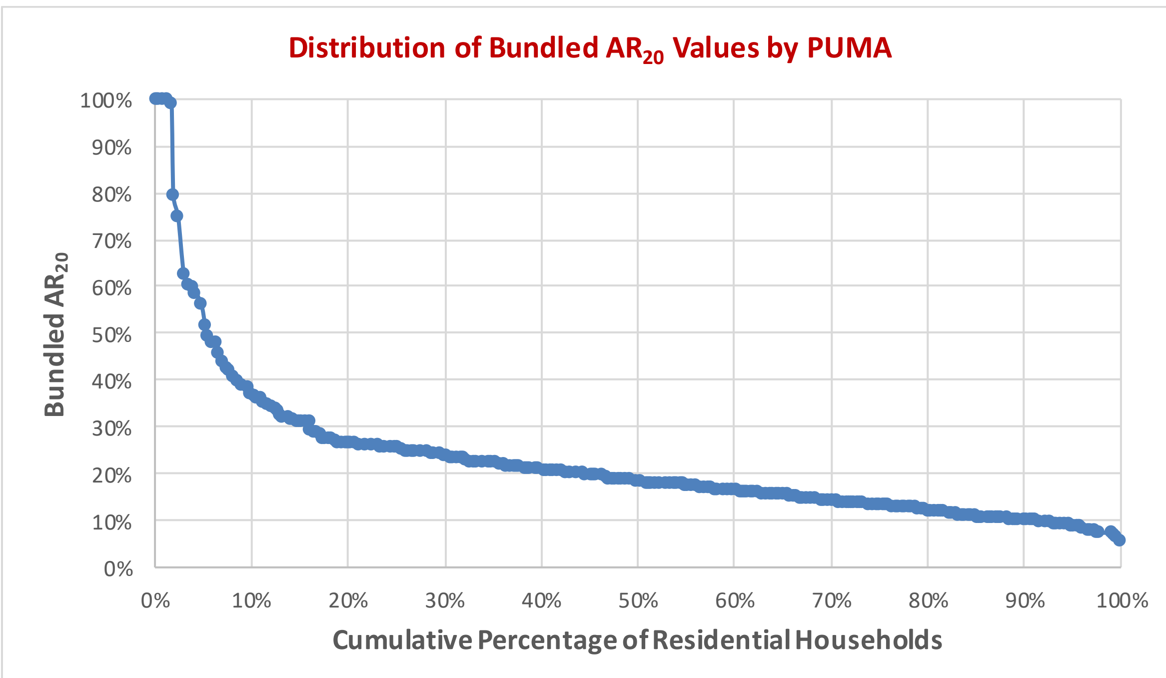
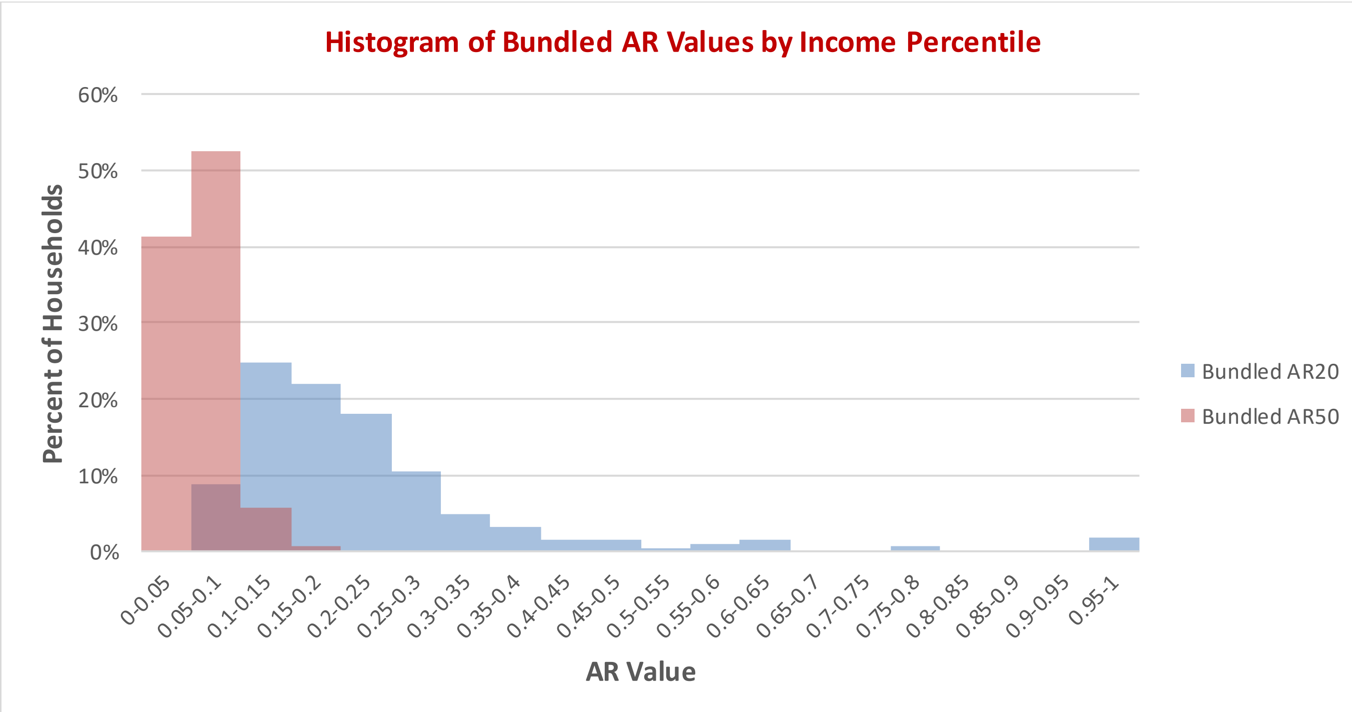
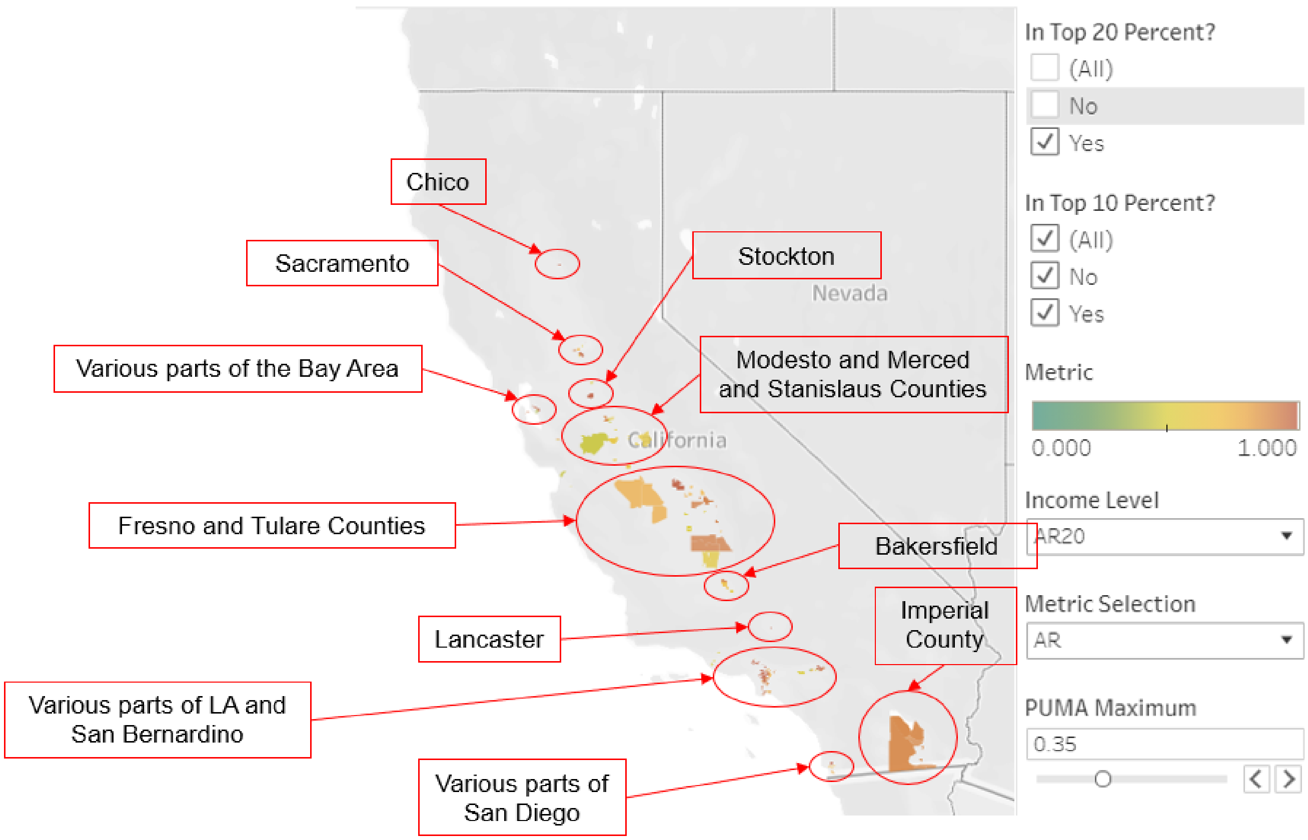


Figure 43: Histogram of Bundled AR Values by Income Percentile



The analysis also identifies the specific geographic areas where utility services are currently the least affordable for low-income households (as measured by AR_{20}) 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 44. 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 44: Census Tracts with Top 20 Percent of Bundled AR_{20} 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.[176] 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.[177]

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.

[176] 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/

[177] 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

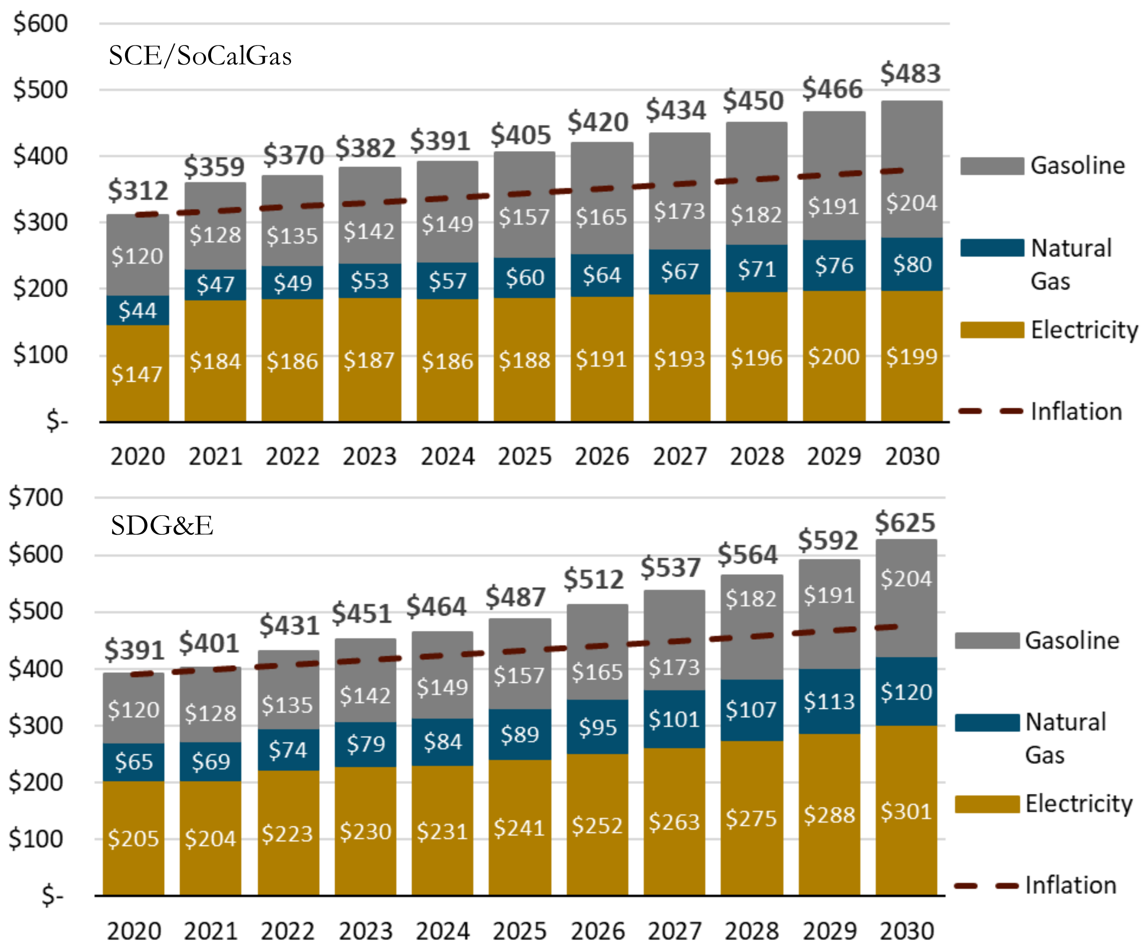
V. CONCLUSION

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 33) and natural gas rate forecasts (Figure 34) were developed for the three large IOUs. A representative household in a hot climate zone was also introduced (Table 28) and energy costs for this customer were shown based on PG&E rates (Figure 36). Variants of Figure 36 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.

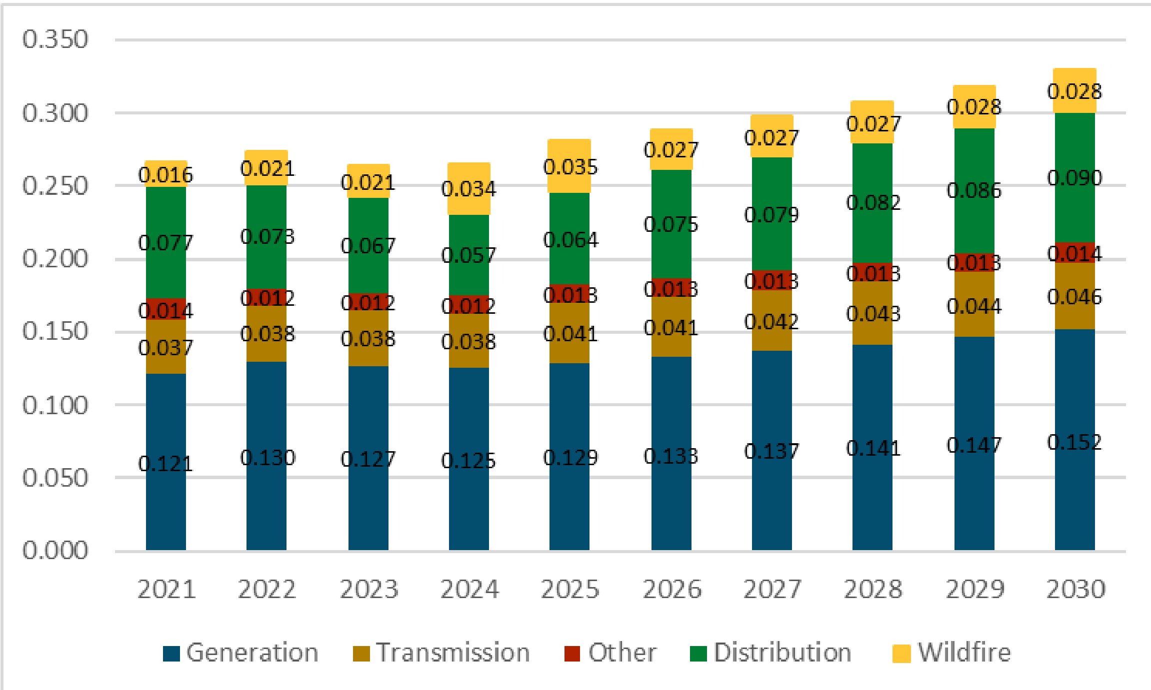
Figure 45: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SCE/SoCalGas Rates and SDG&E Rates



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

Forecasted bundled residential rates in Figure 30 through Figure 32 are shown below with embedded rate component data.[178]

Figure 46: PG&E Forecasted Bundled Residential Rates ($ nominal/kWh), All Embedded Rate Components



[178] The rates in Figures 46 through 48 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

Figure 47: SCE Forecasted Bundled Residential Rates ($ nominal/kWh), All Embedded Rate Components

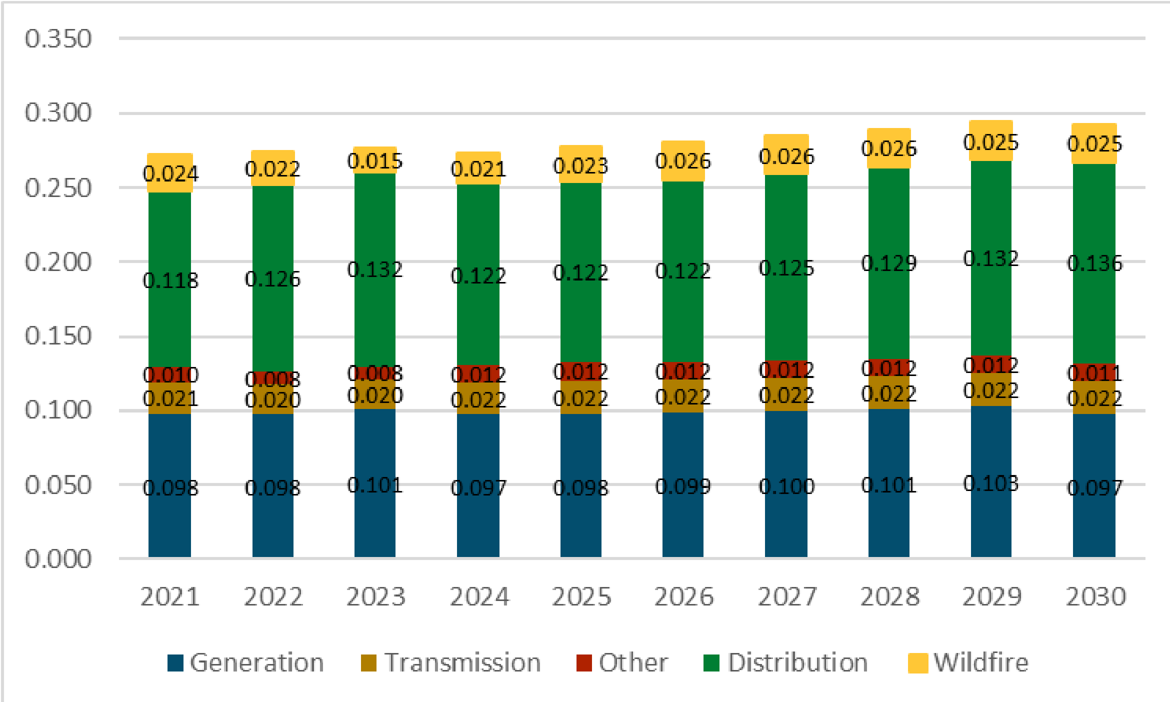


Figure 48: SDG&E Forecasted Bundled Residential Rates ($ nominal/kWh), All Embedded Rate Components