



Actions to Limit Utility Costs and Rates

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

California Public Utilities Commission
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[2018 SB 695 Report](#)

Contributors:

Paul S. Phillips

Masoud Foudeh

Bridget Sieren-Smith

Eyitejumade Sogbesan

Special thanks to:

Neba Bazaj, Suzanne Casazza, Cherie Chan, Kevin Flaherty, Syreeta Gibbs, Bob Levin, Karolina Maslanka, Audrey Neuman, Whitney Richardson, Reese Rogers, Brent Tarnow, and Louis Torres

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1. Introduction

This report is published in accordance with Public Utilities Code Section 913.1, which requires that the California Public Utilities Commission (CPUC) publish an annual report with recommendations that can be undertaken during the succeeding 12 months to limit utility cost and rate increases, consistent with California’s energy and environmental goals. Section 913.1 also requires the CPUC to direct the Investor Owned Utilities (IOUs) to report on measures that the IOUs recommend be undertaken to limit cost and rate increases, and a summary of these reports will be presented in Appendix A along with links to the complete reports. The report is referred to as the “SB 695” report after the legislation that originally required it.

The structure of the SB 695 report has changed over time, to increasingly focus on long-term customer and industry energy trends that affect electric utility costs and ultimately raise rates. In taking a long-term view of system level impacts, opportunities can be identified for decision makers to begin making informed policy choices in the short run to mitigate ratepayer impacts. Some of the broader program cost categories impacting the IOUs’ revenue requirement and rates will be presented along with options for cost reduction that the CPUC may wish to consider in the future proceedings identified in this report. In addition, we view the inclusion of California’s Small Multi-Jurisdictional Utilities (SMJUs) as a priority, and will be incorporating insights on their costs and rates in this report starting in 2019.¹

Cost Containment and the Effects of Retail Competition

The System Average Rate (SAR), defined as an IOU’s total authorized revenue requirement divided by total kilowatt-hour (kWh) sales, is a measurement of an IOU’s cost to serve electricity. Consideration of actions to be taken to limit utility costs should begin with an examination of SAR. However, SAR in and of itself is not a good measure of affordability since electricity bills are determined in part on usage, and average residential usage in California is low compared to that of the United States. Historically, the SAR of each of the three major electric IOUs, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), has tracked inflation in a gradual upward trend. However, starting in 2013, SARs for both SDG&E and PG&E have outstripped the inflationary rate, with SDG&E’s SAR showing larger incremental increases than the other two IOUs.

Increases in SAR may be attributed to either a rise in IOU revenue requirements, a decline in IOU kWh sales, or both. The main contributors to the rise in IOU revenue requirements in recent years include the following: capital costs related to infrastructure upgrades, generation purchased power costs, distribution operations and maintenance costs, security and safety enhancements to the grid, and ensuring reliability and

¹ The SMJUs (Bear Valley Electric Services, PacifiCorp, and Liberty Utilities) operate on a smaller scale compared to the three major investor owned utilities (IOUs). Like the major IOUs, the SMJUs file General Rate Case (GRC) applications requesting authority to recover in rates the cost to own, operate, and maintain the facilities needed to deliver electricity safely and reliably to customers. However, authority to recover in rates the cost of purchasing fuel and power is not granted in an Energy Resource Recovery Account (ERRA) proceeding; rather, it is done differently for each multi-jurisdictional IOU:

resource adequacy. Legislative and regulatory mandates requiring energy-sector related environmental and climate goals as essential investments in California's clean energy future also impact SAR.

In recent years, actual² total system sales³ and bundled sales have flattened out for SDG&E and SCE, while PG&E has had a marked decrease in total system and bundled sales. These flattening or declining trends in total system and bundled kWh sales are driven by the fast-growing number of roof-top solar customers in California, the rapid acceleration of load migration to Community Choice Aggregators (CCAs) across the state, as well as increasing energy-efficiency. Although the IOUs are expected to get a boost to their kWh sales as the result of newly enacted transportation electrification legislation, in the near term it will not be significant enough to offset the ongoing sluggish / declining trend in sales.

Improving cost containment in a competitive energy industry has no singular, one-size-fits-all solution: continually increasing electric utility revenue requirements, decreasing kWh sales, and expanding legislative mandates all make cost control a challenging task. Electric system average rates increased annually from 2013 to 2017 approximately 1% for SCE, 4% for PG&E, and 8% for SDG&E. The magnitude of these rate increases, especially in the case of SDG&E, underscores the need to consider cost implications in the policies and programs that keep California's grid green, safe, and resilient.

Unlike the process for electric utilities, the core gas procurement costs are recovered in utility gas procurement rates which are adjusted monthly, and have fluctuated in recent years relative to electric costs. For 2017, total natural gas utility costs decreased by 0.6% from 2016 versus the 11.9% increase for 2015-2016 and the 0.2% increase from 2014 to 2015.

Vision and Organization of the Report

This report is intended to open a dialog by shedding more light on some of the causes of California's increasing energy program costs and rates, as well as to present options for mitigation. In addition, the report provides a recommended vision and strategy for actions to take as a starting point for addressing these issues, with four key objectives in mind:

- Understanding some of the detailed underlying program and policy drivers of rate trends in California;
- Identifying the challenges and biases in the Cost of Service Regulatory (COSR) model and their impact on rates and value to the consumer;
- Illustrating the nexus and shared rate setting goals between PU Code Section 913.1 and the DER Action Plan for the management of costs and rates;
- Setting forth a vision for additional staff research and examination of select issues in rates on a continuous basis to better inform this report annually.

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

² Actual sales can be found here: <http://www.cpuc.ca.gov/General.aspx?id=12069>.

³ Total system sales include sales to bundled and unbundled (i.e. CCA) customers.

Section 2 addresses general trends in electric rates; Section 3 focuses on legislative programs, with the emphasis on cost of the programs; Section 4 discusses specific trends, such as proliferation of Community Choice Aggregators (CCAs), and also reports on learnings from the Time of Use (TOU) pilot programs implemented last year by the IOUs; Section 5 focuses on Natural Gas and the trends impacting its cost; Section 6 is a general discussion, and a conclusion to the report. Summaries of the IOUs' reports required by section 913.1, as well as links to their full reports, are provided in Appendix A.

A Lexicon of Key Ratemaking Terms and Definitions

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

- **Bundled Customer:** Refers to customers who get all generation, transmission, and distribution services provided by one entity for a single charge. This will include ancillary and retail services.
- **Coincident Demand Charge (CD):** Or peak-related demand charge is a type of Demand Charge that is assessed on the customer's maximum demand in any 15-minute interval during the peak TOU period.
- **Demand Charge (DC):** A charge (in \$/kW) based on a customer's highest moment of electricity usage in a month, other was known as his or her peak demand. A demand charge is assessed on some customers on top of the volumetric charge for total energy usage and is intended to recover the fixed cost of serving that peak load.
- **Distributed Energy Resources (DER):** Distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.
- **Fixed Charge (FC):** A charge assessed on customer bills to recover fixed costs caused by each customer.
- **Load Serving Entities (LSE):** A company or organization that supplies load (electricity) to customers.
- **Non-coincident Demand Charge (NCD):** Type of Demand Charge that is assessed on the customer's maximum demand in any 15-minute interval during the billing cycle.
- **Non-Rate Base Expenses:** Costs that the utility must collect from its customers but does not put into rate base and does not earn a profit. This includes pass through costs for non-utility owned generation and fuel costs.
- **Non-Wires Alternatives (NWA):** Non-traditional solutions, such as DER, that replace traditional transmission and distribution system investments, such as poles, wires, and transformers.
- **Rate Base** is the book value, after depreciation, of the generation, distribution and transmission infrastructure assets owned and operated by the utility. The utilities have the opportunity to earn a profit on assets contained in rate base. Other things being equal, a larger rate base results in higher net income for the utilities.

- **Rate of Return (ROR) on Rate Base:** The cost of paying back utility debt holders with interest, plus the Return on Equity (ROE) to shareholders.
- **Return on Equity (ROE):** Return to utility shareholders, or profit, and it is the most controversial component of the ROR formula.
- **Retail Rates:** Determined by dividing total revenue requirement by total kWh sales (system average rate) and are further subdivided by customer class.
- **Revenue Requirement or utility costs:** Total cost the utility is allowed to recover in rates. This includes operating costs, depreciation, and a reasonable profit.
- **Total Revenue Requirement:** $\text{Rate Base} \times \text{Authorized Rate of Return} + \text{Expenses}$.
- **Un-bundled Customer:** Refers to customers who separate the total process of electric power service from generation to metering into its component parts for the purpose of separate pricing or service offering. The term is usually used for CCA customers in this report.
- **Utility Earnings (or Earning Per Share):** Earnings per share (EPS) represents the portion of a company's earnings, net of taxes and preferred stock dividends, that is allocated to each share of common stock. The figure can be calculated simply by dividing net income earned quarterly by the total number of shares outstanding during the same term.

2. Revenue Requirement Trends

Trends in Electric System Average Rate

Total System Average Rate (SAR), defined as an IOU's total authorized revenue requirement divided by total kWh sales, is a measurement of an IOU's cost to serve. SAR in and of itself is not a good measure of affordability since residential usage billed in California is low at about 60% of average residential usage billed in the United States.⁴ Affordability can be seen more clearly when comparing total bills: Average residential total bills in California are about 84% of average residential total bills across the United States.⁵ In 2018, SCE's total authorized electric system average rate was 14.61¢/kWh, PG&E's was 16.27 ¢/kWh, and SDG&E's was 22.50 ¢/kWh, based on each IOU's January 1 authorized revenue requirement and forecasted total sales.⁶ Starting in 2013, SDG&E's electric SAR began to outpace the generally trending upward SARs of the other IOUs, as shown in the Figure 1.

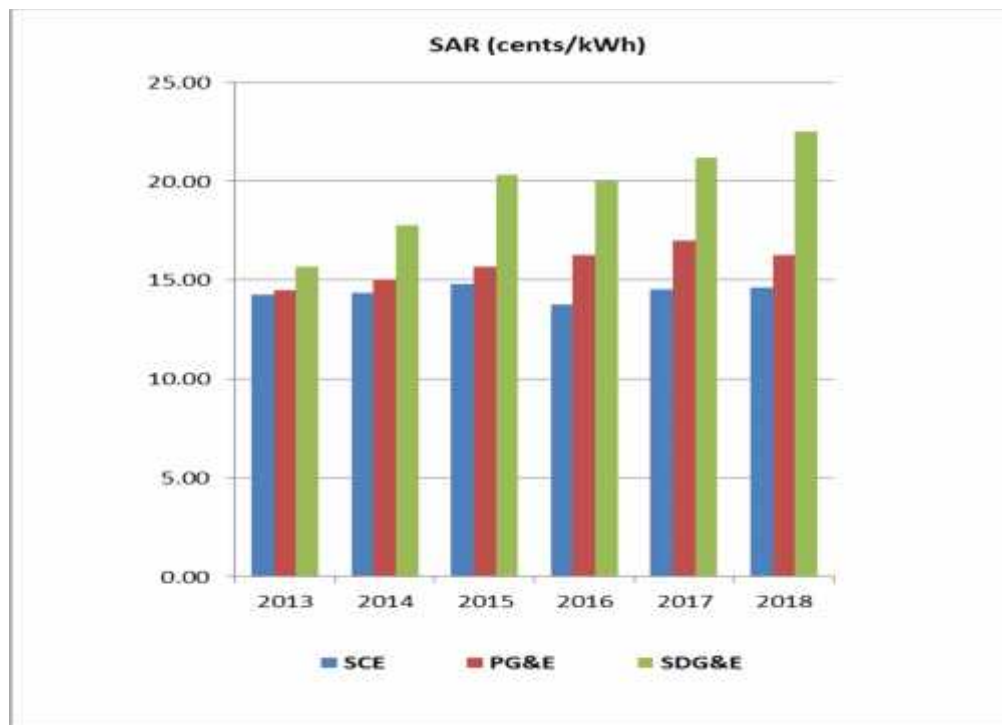


Figure 1: System Average Rate (SAR)⁷

⁴ U.S. Energy Information Administration (U.S. EIA), Electricity Data, Retail Sales, Total Electric Industry, Residential, annual average 2013 – 2017 data by number of customer accounts

⁵ U.S. EIA, Electricity Data, Revenue from Retail Sales, Total Electric Industry, Residential, annual 2013 – 2017 data by number of customer accounts

⁶ SCE Advice Letter 3695-E-A, PG&E Advice Letter 5231-E, and SDG&E 3137-E, all effective as of 1/1/18

⁷ Based on January 1 authorized revenue requirement, including amortizations of balancing and/or memorandum accounts, and forecasted sales

In recent years, electric SAR have broken away from the historic trend of roughly tracking inflation and have instead generally increased across all IOUs at a faster rate than inflation. Figure 2 shows this effect by comparing the actual SAR with the inflation-adjusted SAR for each IOU (e.g. the SAR that would have resulted had the previous year’s SAR only increased by the inflationary rate):

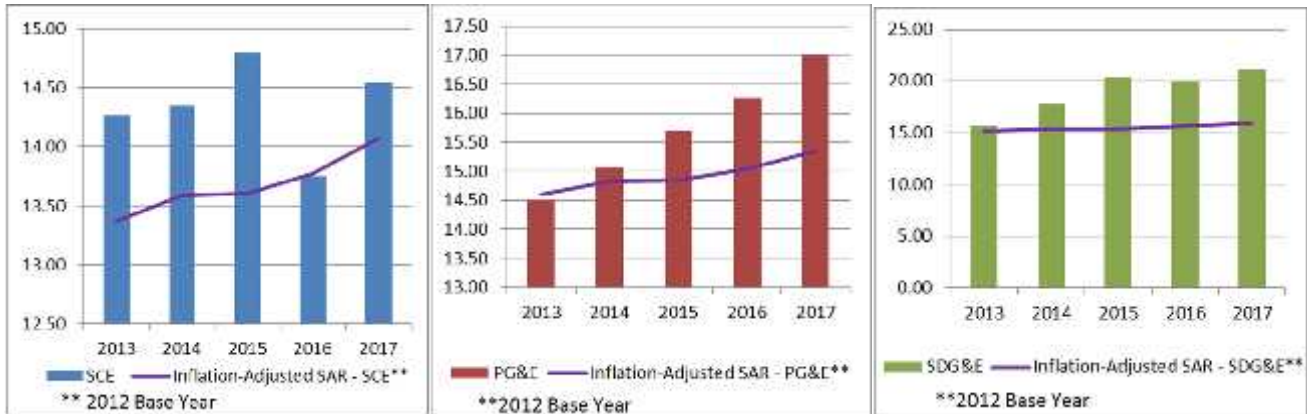


Figure 2: Actual SAR vs. Inflation-Adjusted SAR (¢/kWh) by IOU

Over the period 2013 – 2017, electric SARs for both PG&E and SDG&E consistently outstripped the inflationary rate. Electric system average rates increased annually from 2013 to 2017 by approximately 4% for PG&E, and approximately 8% for SDG&E, compared to an average annual inflation rate of 1.3%⁸ over the same period. SCE’s upward trending SAR from 2013 to 2015 was reset to a lower level in 2016, resulting in an overall annual SAR of approximately 1% for the 2013 – 2017 period.⁹

Customers have been able to offset higher electric retail rates, to some extent, with purchasing less generation and distribution kWh due to energy efficiency and other demand-side energy management programs, as well as investing in industry-driven trends such as customer self-generation of electricity (primarily solar installations). CPUC directed behind-the-meter energy storage and other distributed energy resource (DER) programs may increasingly allow for additional customer savings.

However, as customers increasingly begin to provide their own electricity through solar or other DERs, or as customers depart from the IOUs to other Load-Serving Entities,¹⁰ upward rate pressure is placed on remaining customers as the utilities will need to collect costs from a dwindling sales volume. Some of these upward rates pressures could impact customers departing to CCAs since revenue loss to self-service of

⁸ Inflation measured by CPI from U.S. Bureau of Labor Statistics

⁹ The 2016 AB 67 Report, *California Electric and Gas Utility Cost Report* states that an incremental decline in SCE’s SAR in 2016 resulted from recent General Rate Case (GRC) outcomes as well as the decommissioning of the San Onofre Nuclear Generating Station (SONGS).

¹⁰ Load-Serving Entities include Community Choice Aggregators.

electricity will largely impact the distribution charges which are paid by both bundled and unbundled customers.

Sales forecasts are used in setting both the authorized revenue requirement and for setting rates to collect these authorized revenue requirements. Accurate sales forecasts are critical in matching rates to costs as closely as possible. Figure 3 shows the comparison of forecasted total sales to actual total sales.

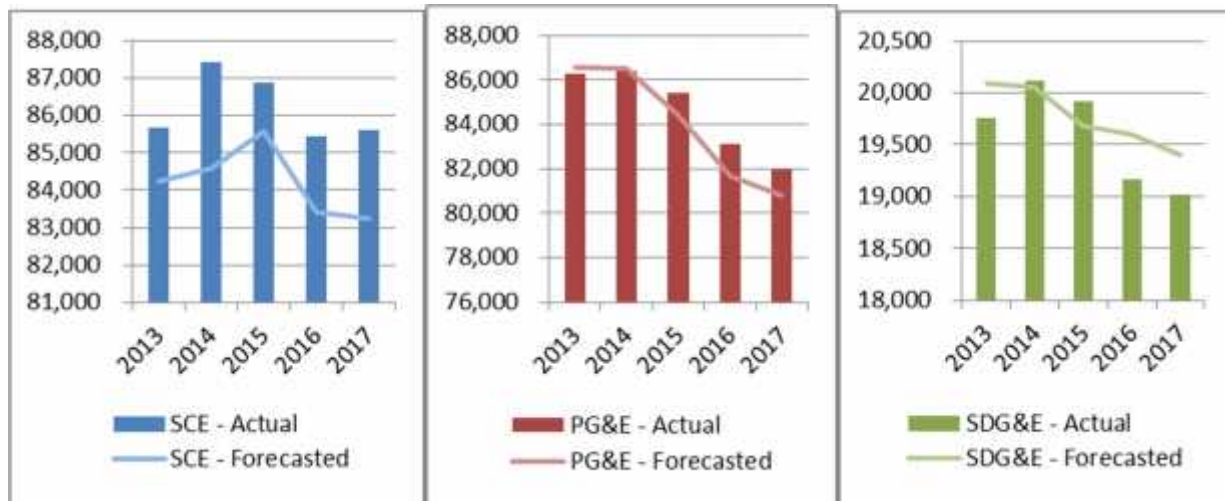


Figure 3: Forecasted Total Sales¹¹ vs. Actual Total Sales (GWh), by IOU

There has historically been a mismatch between forecasted and actual sales in general, however, and for SDG&E, this mismatch has generally resulted in an under-estimation of actual sales.¹² Rate pressure is exacerbated when actual sales are less than the sales forecasts used for setting the authorized revenue requirement. Any mismatch between expected and actual sales that results in greater (or lesser) revenue being received by the utility does not inure to the IOU in the form of profit or loss, but rather is rebated (or surcharged) to ratepayers. However, decoupling allows the CPUC to separate the link between revenues and sales, which means financial pressure on the utility to sell a unit of electricity is removed; so is the disincentives to promote energy efficiency and conservation among customers.

Load defection due to customer departure to CCAs results in a smaller rate impact compared to effects resulting from customer self-generation or energy efficiency as the IOUs continue to collect the distribution revenue requirement from CCA customers for their use of IOU delivery infrastructure.

¹¹ Sales forecasts are the same as those used for calculating SAR as of January 1. For SCE and PG&E, these forecasts are derived from annual Energy Resource Recovery Account (ERRA) proceedings, and for SDG&E, these forecasts have been derived from GRC and other proceedings. Actual sales are matched to forecasted sales for Jan 1 of the following year, in order to capture all updates to forecasted sales that may have occurred during the year.

¹² For 2018, sales are forecasted to decline from 2017 actual sales 1.4% for PG&E and 2.9% for SCE.

The longer term trend points to continued growth in rooftop solar penetration, rapid proliferation of CCAs in IOU territories,¹³ and large investment in DSM programs such as energy efficiency as driving load defection.¹⁴ As customers continue to depart from the IOUs, the upward revenue pressure placed on remaining customers illustrates the inherent weaknesses with a Cost of Service Regulation (COSR) model that depends in part on increasing sales. Sales forecasting methodologies must be continually refined to achieve the highest degree of accuracy possible to minimize this effect.

General Trends in Electric Revenue Requirements¹⁵

Utilities file detailed descriptions of the costs of providing service (commonly referred to as “revenue requirements”) and request authorization of these costs in various proceedings. In its authorization of an IOU’s electric revenue requirement, the CPUC strives to provide electric utility customers safe, reliable utility service and infrastructure, with a commitment to environmental enhancement and a healthy California economy.

Rate charges appear on customer bills as separate line items. The grouping of rates into generation, distribution, and transmission is primarily based on the costs of each of these functional areas of utility business. In addition, the distribution rate component includes non-by-passable costs of public purpose programs that are paid by all customers who use the utility distribution system.

Steady Increases in Rate Base Over the Past Decade

Return on rate base is a component of a utility’s authorized revenue requirement and is calculated based on the net book value of generation, transmission and distribution assets. The CPUC approves the level of capital expenditure for generation and distribution¹⁶ assets on a forecast basis for each IOU in General Rate Case (GRC) proceedings, and may disallow the expenditure if it is determined to be unreasonably or imprudently incurred

¹³ Load defection due to customer departure to CCAs results in a smaller rate impact compared to effects resulting from customer self-generation or energy efficiency as the IOUs continue to collect the distribution revenue requirement from CCA customers for their use of IOU delivery infrastructure.

¹⁴ Load defection due to customer departure to CCAs results in a smaller rate impact compared to effects resulting from customer self-generation or energy efficiency as the IOUs continue to collect the distribution revenue requirement from CCA customers for their use of IOU delivery infrastructure.

¹⁵ More detailed descriptions of how utility revenue requirements are determined can be found in the 2017 AB 67 Report (filed April 2018), available on the CPUC website ([AB 67 Report](#)). All dollars not adjusted for inflation unless otherwise indicated.

¹⁶ Transmission capital expenditure is approved by FERC.

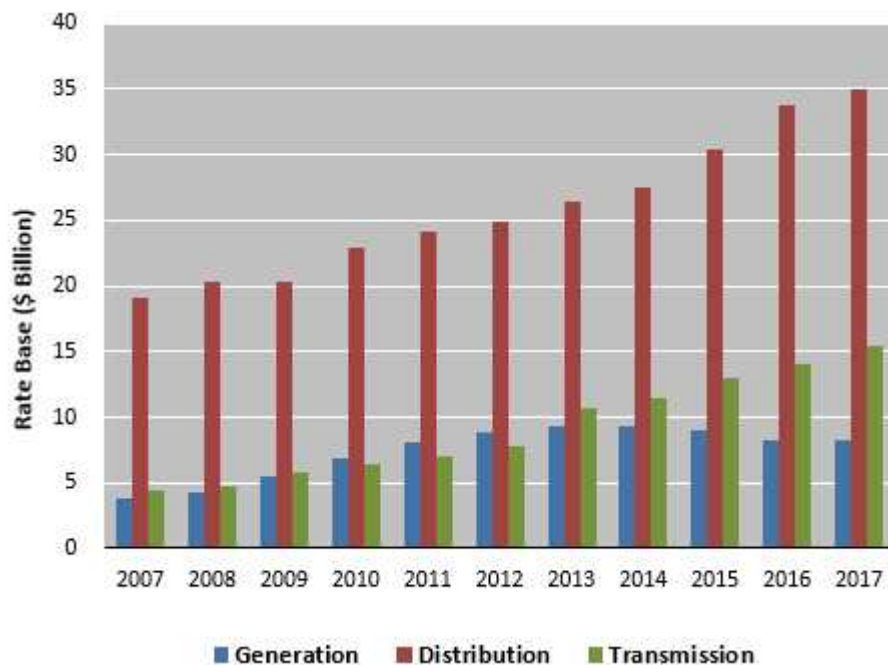


Figure 4: Trends in Utility Rate base - All IOUs

Figure 4 indicates that between 2007 and 2017, the utilities’ total rate base more than doubled in size from \$27.4 billion to \$58.6 billion, or a 114% increase over the past decade.¹⁷ CPUC-jurisdictional rate base has increased from \$23.0 billion to \$43.2 billion, an 88% increase, over the same period,¹⁸ triggering corresponding increases in GRC revenue requirements.

While the distribution component of utility rate base is the largest in absolute terms, the largest increase has occurred in the transmission component, which increased from \$4.5 billion to \$15.4 billion, or by 242% over the period 2007 - 2017.¹⁹

Cost Recovery²⁰

In addition to earning a return on net investments in generation and distribution assets, revenue authorized by the CPUC through GRC proceedings is intended to provide the IOUs a reasonable opportunity to recover operation and maintenance costs, depreciation, and taxes on a forecast basis. In addition, fuel and power procurement-related costs are recovered on a pass-through basis through annual Energy Resource Recovery Account proceedings.

¹⁷ When adjusted for inflation, the 2007 total rate base corresponds to \$32.4 billion, resulting in an approximately 81% increase in 2017 dollars.

¹⁸ When adjusted for inflation, the 2007 CPUC-jurisdictional rate base corresponds to \$27.0 billion, resulting in an approximately 60% increase in 2017 dollars.

¹⁹ When adjusted for inflation, the 2007 transmission rate base corresponds to \$5.3 billion, resulting in an approximately 191% increase in 2017 dollars.

²⁰ All cost recovery data from Assembly Bill (AB) 67 reports, *California Public Utilities Code Section 913 Annual Report to the Governor and Legislature*, unless otherwise indicated; AB 67 reports available on the CPUC website.

Figure 5 shows generation cost recovery for all IOUs through GRC and ERRA proceedings over the past decade..²¹

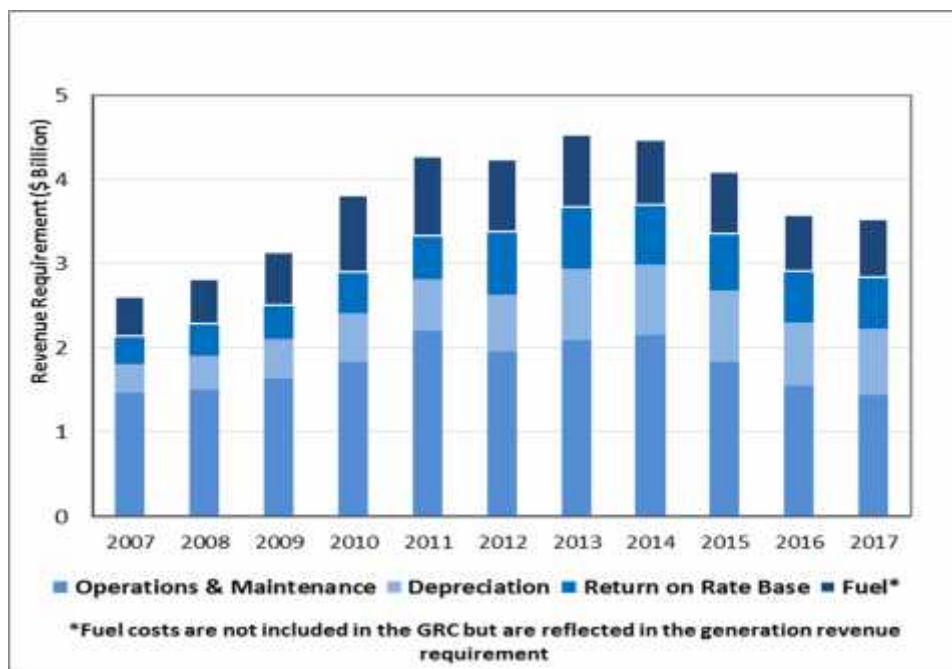


Figure 5: Trends in General Rate Cases - Generation Revenue Requirements

As shown in Figure 5, the generation revenue requirement corresponding to GRC and Utility-Owned Generation (UOG) fuel across all three IOUs rose to a peak in 2013 and has been on a decline since then, with the largest decrease in the Operations & Maintenance category.²² However, the generation revenue requirement corresponding to purchased power for all three IOUs, while lower in 2017 than in 2007, has shown an overall increase since 2011, as indicated in Figure 6.

²¹ Return on rate base, while not cost recovery, is shown as part of the revenue requirement.

²² Decrease 2013 – 2017: Operations & Maintenance 45%; Depreciation 7%; Return on Rate base 20%; Fuel 24%

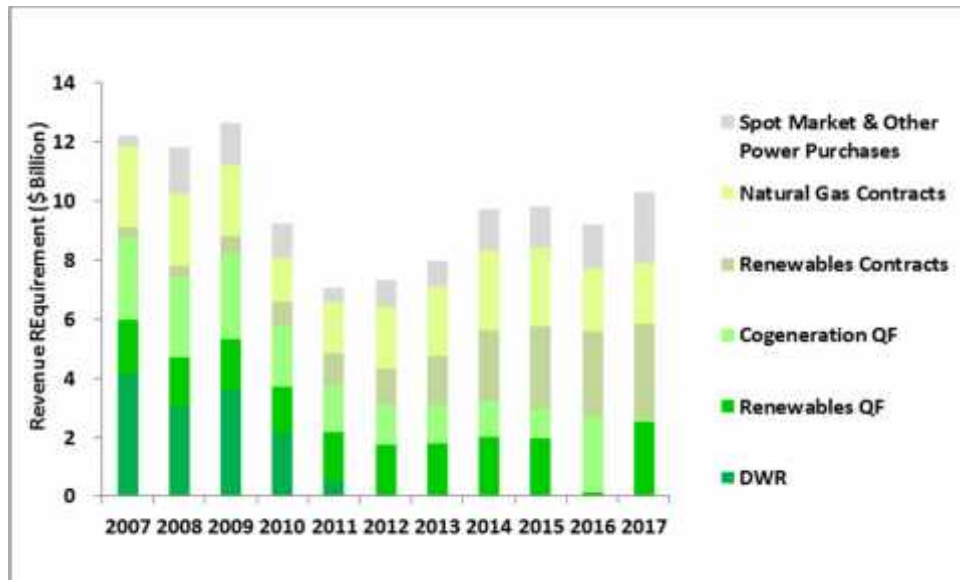


Figure 6: Trends in Purchased Power - All IOUs

Renewable energy resources from both contracts and qualifying facilities have been comprising an ever-larger percentage of the IOUs’ total purchased power costs over the past decade. From 2007 to 2017, this percentage increased from approximately 17% to approximately 55% of the total purchased power costs recovered in the three major electric IOUs’ authorized revenue requirements.

Across all three IOUs, the distribution revenue requirement has been on a steady increase, with a decline in 2017 in overall distribution revenue requirement, primarily due to lower depreciation recovered in 2017 than in 2016, as shown in Figure 7.

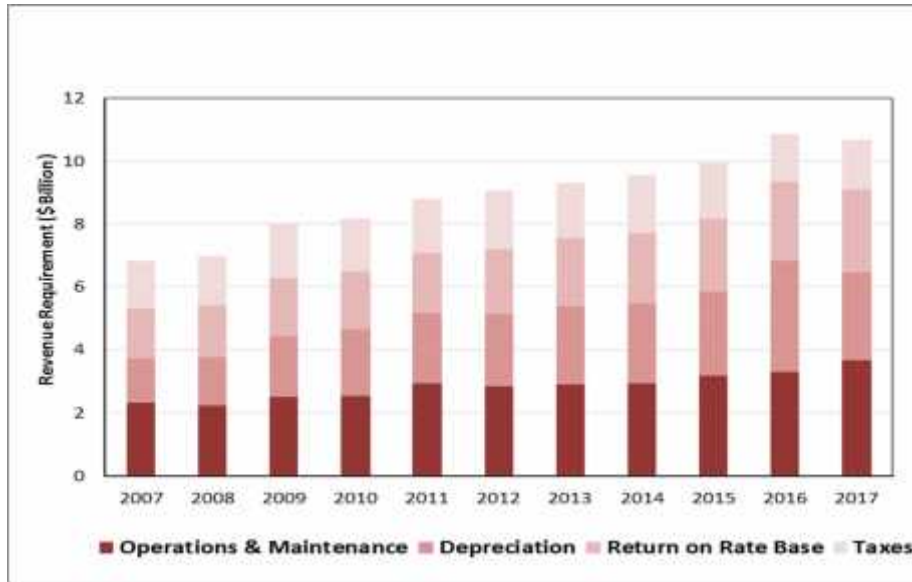


Figure 7: Trends in General Rate Cases - Distribution Revenue Requirements

The following charts in Figure 8 show cost recovery for all IOUs with respect to select DER and Public Purpose Programs in recent years:

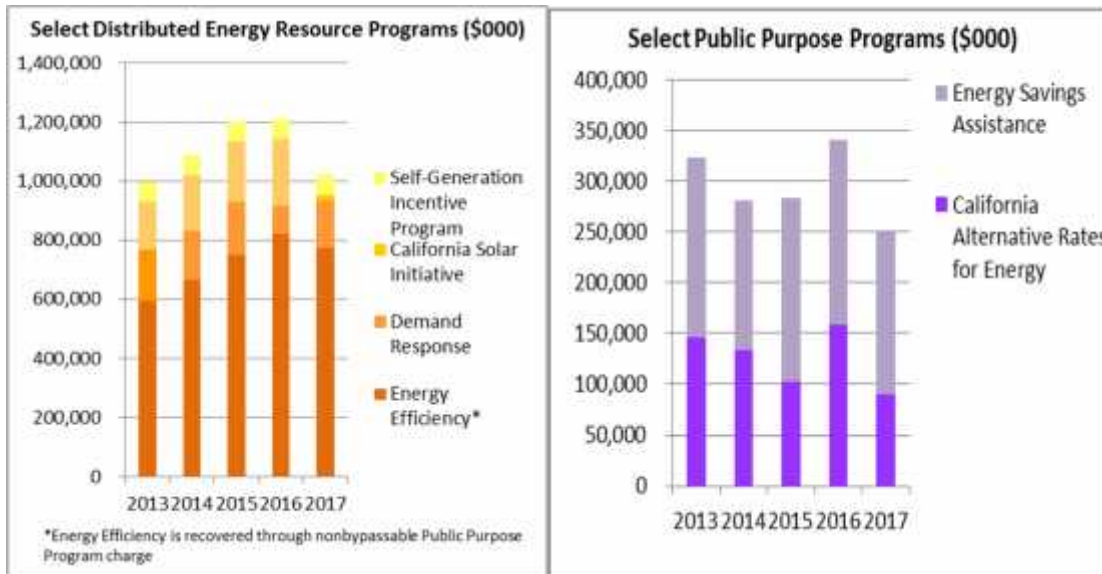


Figure 8: Trends in Select DER and Public Purpose Programs - All IOUs

These charts reflect the authorized revenue requirement forecasted on January 1 of each program year and revenue adjustments authorized as of January 1 resulting from under- or over-collecting the program authorized revenue requirement in prior years. While Energy Efficiency public-purpose expenditures have generally been trending upward, the energy efficiency programs are required to meet a cost effectiveness test where total costs of the programs are to be offset with savings by reduced usages. This means that while energy efficiency programs show up as a cost under the public-purpose programs, there should be a corresponding savings in other cost categories and in overall bills due to reduced usage.

Transmission Costs on the Rise

Transmission costs are authorized by the Federal Energy Regulatory Commission (FERC). The CPUC advocates for just and reasonable rates for California retail ratepayers at FERC proceedings addressing transmission and sale of electricity in wholesale markets. Figure 9 shows cost recovery for all IOUs through Transmission Owner(TO) proceedings over the past decade:

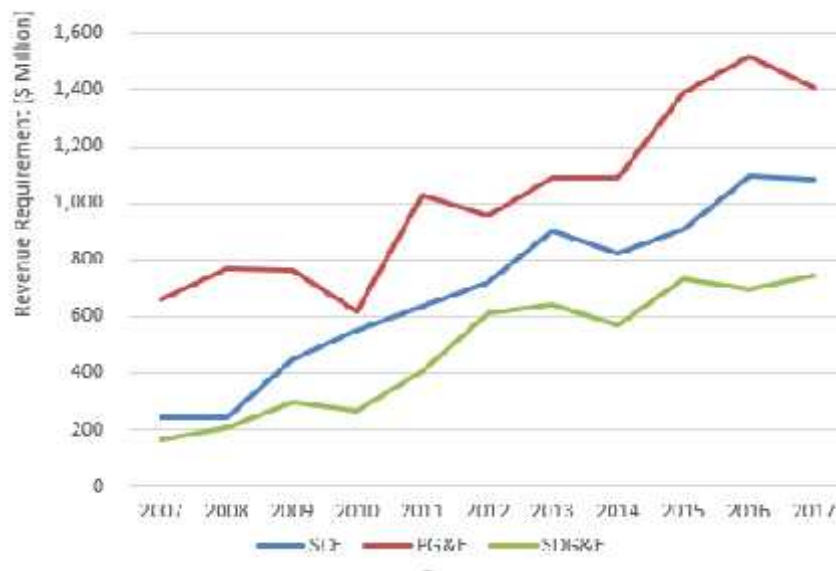


Figure 9: Trends in Transmission Revenue Requirements²³

TO revenue requirements for the major electric IOUs have been trending sharply upward. Between 2007 and 2017, the TO revenue requirement for the major electric IOUs approximately tripled, from \$1.1 billion to \$3.2 billion.²⁴ On an annual average basis, the TO component of the IOUs' total authorized revenue requirement increased approximately 35% for SCE, 11% for PG&E, and 36% for SDG&E over the 2007 – 2017 period. Historically, much of the increase has been due to transmission plant capital additions built by

²³ Does not include costs related to Reliability Services or Transmission Access Charge

²⁴ When adjusted for inflation, the 2007 transmission revenue requirement corresponds to \$1.3 billion, resulting in an approximately 150% increase in 2017 dollars.

the utilities. More recently, the increases result from replacing and modernizing aging infrastructure, interconnecting new electric generation, and compliance with updated North American Electric Reliability Corporation (NERC) requirements.

Further, the CPUC has learned that several utilities have approved transmission projects without specific review or approval from the CPUC or the CAISO²⁵. The CPUC believes that this lack of oversight and review of the construction of capital projects, which must ultimately be paid for by the ratepayers, is a violation of FERC's Order 890²⁶. For this reason, the CPUC is seeking more transparency and stakeholder involvement in the transmission planning process in these proceedings. A more transparent review process should moderate the growth of capital addition rate base and therefore rising transmission rates.

²⁵ There are two FERC dockets in which the CPUC is active: PG&E FERC Docket EL 17-45, and SCE FERC Docket ER 18-370

²⁶ FERC 890 information can be found on <https://www.ferc.gov/legal/maj-ord-reg.asp>

3. Legislative Programs – Present and Future Cost Implications

Distributed Energy Resources (DER) Action Plan

The California Legislature recently enacted legislation to further California’s deep commitment to reducing greenhouse gas emissions and deploying distributed energy resources. Senate Bills 350 and 32, approved by the Governor in 2015 and 2016, commit California to reduce 2030 greenhouse gas emissions (GHG) by 40% below 1990 levels, by increasing to 50% the share of electricity to be produced by renewable generation, doubling targets for energy efficiency, and encouraging widespread transportation electrification. Assembly Bill 327, approved by the Governor in 2013, requires reform of utility distribution planning, investment, and operations to “minimize overall system cost and maximize ratepayer benefits from investments in preferred resources,” while advancing time- and location-variant pricing and incentives to support distributed energy resources.²⁷

Distributed energy resources (DER), which are defined as distribution-connected distributed generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies, are supported by a wide-ranging suite of CPUC policies. In November 2016, the CPUC published the DER action plan,²⁸ a roadmap with a long-term vision and near-term and long-term efforts to support the vision to help proceedings and initiatives that are related to: 1) Rates and Tariffs; 2) Distribution Grid Infrastructure, Planning, Interconnection and Procurement; and 3) Wholesale DER Market Integration and Interconnection.

Electric Vehicles (EV)

Background and Status

The CPUC and IOUs are responding to several mandates, both legislative and executive orders, related to Electric Vehicle (EV) programs.

Senate Bill 350 (DeLeon, 2015) established a goal of accelerating statewide transportation electrification. The CPUC and the IOUs worked on implementing the goals laid out in SB 350 throughout 2017, and will continue to do so in 2018, which are described in more detail below.

In 2017, Governor Brown signed AB1082²⁹ and AB 1083³⁰ (Burke, 2017) into law. AB 1082 authorizes the utilities to submit applications for pilot projects to install EV charging infrastructure at school facilities and other educational institutions. AB 1083 authorizes the utilities to submit applications for pilot projects to

²⁷ Public Utilities Code §769(c)

²⁸ [DER Action Plan](#)

²⁹ [AB 1082](#)

³⁰ [AB 1083](#)

install EV charging infrastructure at state parks and beaches. Both bills direct the IOUs to file these proposals for CPUC's approval by July 30, 2018 and require a decision by December 31, 2018.

In January 2018, the CPUC received further direction on transportation electrification. Governor Brown expanded his 2012 executive order³¹ calling for 1.5 million zero-emission vehicles by 2025 in a new executive order³² that adds a target of 5 million zero-emission vehicles on the road in California by 2030.³³ It also established a goal of 250,000 electric vehicle charging stations and 200 hydrogen fueling station installed by 2025. These targets will drive much of the transportation electrification work the CPUC and IOUs do in the coming years.

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

- Coordinate the buildout of EV charging infrastructure
- Establish EV rates
- Utilize vehicle-to-grid integration technologies that allow EVs to serve as a grid resource, facilitate increased renewable energy usage, and mitigate duck curve³⁴ imbalances.

For the infrastructure buildout goal, the CPUC and the IOUs will assist in advancing the infrastructure market to remove barriers to other forms of long-term investment. This involves financing EV infrastructure in underinvested areas, and in a manner that minimizes ratepayer costs and does not impede competition. The existing transportation electrification programs are already working toward this objective through the installation of charging equipment at multi-unit dwellings, workplaces, and destination centers, all testing slightly different ownership and cost models. Additionally, In January 2018 the CPUC approved 15 pilot programs that also address infrastructure; more programs are currently under review.

With respect to establishment of EV rates, the CPUC is promoting rates that enable customers to choose lower fueling costs, and do not unfairly shift costs to non-EV drivers. PG&E, SDG&E, and SCE all have residential rates designed for EV drivers. SCE also has commercial EV rates geared towards those who are operating a fleet of vehicles. The IOUs are also piloting EV sub-metering where they are testing the efficacy of using sub-meters to separate residential home load from EV charging. Additionally, there are several other proposed EV rates currently under review, including a commercial EV rate from SDG&E, and a commercial EV rate proposal expected from PG&E later this year.

Regarding Vehicle-Grid Integration(VGI), the CPUC aims to enable EV charging that benefits the grid by encouraging charging at times of the day and locations on the grid that facilitate the use of low-cost renewable energy. The goal is to enable EVs to communicate with the grid to provide demand response, storage, and vehicle-to-grid services. Work is still in the early stages for vehicle-grid integration, but the

³¹ [Executive Order B-16-2012](#).

³² [Executive Order B-48-18](#).

³³ As of January 2018, the Governor's office believes there are more than 350,000 "zero-emission vehicles" (e.g. BEVs, PHEVs, FCEVs, and plug-in FCEVs) in the state.

³⁴See [CAISO Duck Curve](#).

CPUC and IOUs are piloting several programs to better understand this area, including the LA Air Force Base pilot, the EV Storage Accelerator pilot at UCSD, and the recently approved PG&E school bus renewables integration pilot.

EV Pilot Program Status Update

The CPUC oversees several transportation electrification pilot programs, which the CPUC approved in 2016. The three light-duty EV infrastructure pilots, with a total budget of \$197 million for approximately 12,500 EV chargers, and the NRG Settlement ³⁵, with a budget of \$102.5 million, are the largest. The light duty EV infrastructure pilots are in various stages, with SCE being the furthest along, and PG&E having just begun construction in January 2018. Table 1 shows the size, status and budget of these pilot programs.

	SDG&E	SCE	PG&E
Program timeline	Dec. 2016 – Dec. 2019	Apr. 2016 – Apr. 2018	Jan. 2018 – Jan. 2021
Budget	\$45M	\$22M	\$130M
Scope	3,500 charge ports	1,500 charge ports	7,500 charge ports
Ports installed³⁶	359 ports	803 ports	22 ports
Market Segments	<ul style="list-style-type: none"> ▪ Multi-unit dwellings (40% target) ▪ Workplaces ▪ Disadvantaged communities (10% target) 	<ul style="list-style-type: none"> ▪ Multi-unit dwellings (25% target) ▪ Workplaces ▪ Destination centers ▪ Disadvantaged communities (10% target) 	<ul style="list-style-type: none"> ▪ Multi-unit dwellings (20% target) ▪ Workplaces ▪ Disadvantaged communities (15% target)
Ownership	SDG&E	Site Host	Site host or PG&E ³⁷

Table 1: IOU Light Duty Infrastructure Pilots

The utilities are just beginning to implement these pilots, so costs will likely begin appearing in rates starting in 2019. Table 2 shows the total cost of approved programs per IOU.

Utility	Budget for Priority Review Project
SDG&E	\$17,883,867
SCE	\$15,445,000
PG&E	7,783,900
ALL 3 IOUs	\$41,112,767 (not including authorized cost for evaluation)

Table 2: EV Projects Per IOU

³⁵ In 2012, the FERC approved an agreement between NRG Energy and the CPUC to settle outstanding legal issues regarding the California energy crisis. The Settlement requires NRG to invest \$102.5M in EV charging infrastructure at no cost to site hosts. NRG began year 6 of the settlement on Dec 6, 2017.

³⁶ As of February 2018.

³⁷ PG&E is allowed to own the infrastructure at multi-unit dwelling and disadvantaged community sites, and has a limit of owning 35% of the total program infrastructure.

The CPUC is still reviewing four additional proposals for larger programs, and two rate proposals. The total cost of these proposed programs is approximately \$1 billion. If approved, the costs would likely begin to appear in rates starting 2019. In January 2018, SDG&E submitted an additional application to address the medium and heavy-duty transportation sector, with a proposed project budget of \$150.6 million, and also applied for a school bus vehicle-to-grid pilot, with a proposed budget of \$1.7 million. These two proposals are also under the umbrella of SB 350.

2018 Transportation Electrification Activities and Proceedings

Transportation electrification continues to be a key area of focus for the utilities, legislators, and the state agencies. As such, the programs overseen by the CPUC are growing in number and scope. In 2018, the CPUC expects additional applications proposing programs in response to AB 1082 and AB 1083, and other transportation electrification programs.

As of December 2017, the 3 large IOUs estimate the following growth in EVs for their territories³⁸, shown in Figure 10.

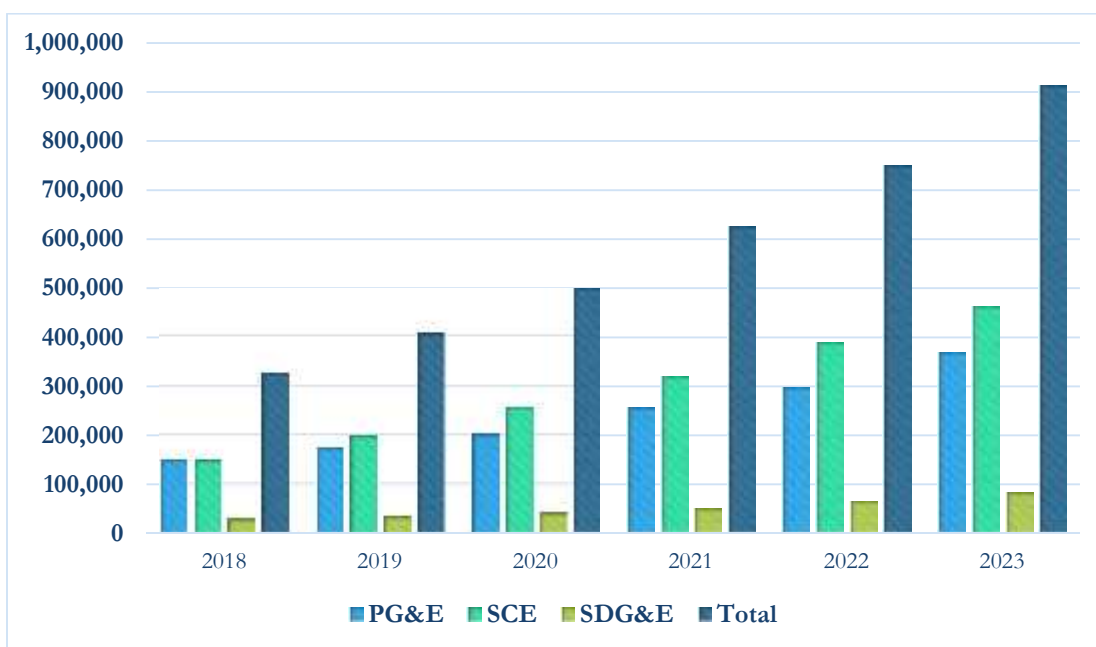


Figure 10: EV Growth in IOU territories

The transportation electrification programs aim to increase growth in EV sales in response to the Governor’s executive orders. As the CPUC, IOUs, and other state agencies work towards meeting these

³⁸ See 2017 Joint IOU EV Load Research [Report](#).

goals for infrastructure and EV growth, the transportation electrification programs that the CPUC reviews and oversees will continue to grow, and the costs from these programs will increase rates.

Growth in EVs also has the potential to increase utility load and offset declining kWh sales. Growth in EV deployment will likely lead to higher overall electricity demand, which can enable better management of energy supply and imbalances reflected through demand response, storage, and other vehicle-grid-integration enabled services. This all may have the effect of helping to drive down rates for all customers. Ultimately, any favorable impacts of increased sales on rates will depend on the increase in revenue requirement needed to fund EV programs.

In order to keep rates in control, the CPUC must continue to weigh the full costs and benefits associated with IOU investment in EV infrastructure and continue to design policies that ensure the investments are as cost-effective as possible, in the best interest of ratepayers, and within the scope of the IOUs' responsibilities.

Renewable Portfolio Standards (RPS)

Background and Status

SB 1078 established the Renewable Portfolio Standard (RPS) in 2002, requiring the state to meet 20% of its electricity demand from eligible renewable energy resources by 2010 and to maintain 20% renewables thereafter. Eligible resources include wind, solar photovoltaics, solar thermal, tidal wave, small hydroelectric, geothermal, biodiesel, biomass and biogas.

On October 7, 2015, Governor Brown approved SB 350 (De León) or the "Clean Energy and Pollution Reduction Act of 2015." The bill revised the RPS target to obtain 50% of total retail electricity sales from renewable resources by December 31, 2030, with interim targets of 40% by December 31, 2024, and 45% by December 31, 2027.

To understand the impact that RPS costs will have on ratepayers, the CPUC sets cost-effectiveness policies and collects various price data to understand cost trends. The IOUs use competitive procurement mechanisms and a least-cost, best-fit evaluation methodology, to ensure procurement of renewable resources that provide the most value in their RPS Procurement Plans. Although the CPUC has not previously established cost limitations for renewable procurement, it is using the IRP as a way to identify the most cost-effective resources to inform future procurement activities.

The CPUC tracks the cost of renewables to understand the impact on ratepayers. Relative to other renewable technologies, the utility-scale solar and wind market has expanded rapidly and the prices have decreased dramatically over the last decade. The consistent decrease in the average prices of solar PV projects are reflected in the sharp drop in IOU contract prices observed from 2008 to 2016. Similarly, the decrease in the cost of developing wind projects can be observed through the decline in the average prices of wind contracts from 2007 to 2015. The prices of utility-scale solar contracts have decreased roughly 77%

from 2010 to 2016, from an average of \$127.55/MWh to \$29.17/MWh. Similarly, the average prices of utility-scale wind contracts have decreased approximately 47% in the last decade from an average of \$96.72/MWh in 2010 to \$50.99/MWh in 2015.

As of 2017, roughly 35% of the IOUs' generation came from renewable resources. From 2003 to 2016, the average time-of-day adjusted price of contracts approved by the CPUC has decreased from 9.4 cents to 6.2 cents/kWh in real dollars.³⁹ The decrease in RPS contract prices in terms of real dollars indicates that the renewable market in California is robust and competitive and has matured since the start of the RPS program. In May 2018, the CPUC will release a report on the costs and savings for the RPS program in 2017.

2018 RPS Activities and Proceedings

In 2018, the CPUC will complete its implementation of SB 350 with a decision regarding RPS enforcement under the new statute. Also in 2018, the current RPS proceeding, R.15-02-020, will conclude and a new proceeding will be initiated and scoped to coordinate with other CPUC activities, such as IRP.

Integrated Resource Planning (IRP)

Background and Status

Pursuant to SB 350 and CPUC directive,⁴⁰ Long Term Procurement Planning has transitioned to an Integrated Resource Planning (IRP) process, which is designed to ensure that the electric sector is on track to help California achieve its statewide 2030 GHG reduction target, at the lowest possible cost, while maintaining electric service reliability and meeting other state goals.

Specifically, statutes⁴¹ require the CPUC's IRP process to identify a diverse and balanced portfolio of resources to ensure a reliable electricity supply that provides optimal integration of renewables while:

- Meeting the GHG emissions reduction targets established by ARB;
- Having a portfolio that relies upon zero carbon-emitting resources to the maximum extent reasonable;
- Procuring at least 50% eligible renewable energy resources by 2030,
- Serving customers at just and reasonable rates;
- Minimizing impacts on ratepayers' bills, and;
- Ensuring system and local reliability.

Through the IRP process, the CPUC has an opportunity to identify optimal resource solutions that might not otherwise be found, and to guide resource investment decisions across all types of Load Serving Entities (LSEs) and resource programs. IRP will also allow the CPUC to examine multiple, largely separate

³⁹ The CPUC used the Handy-Whitman Index of Public Utility Construction Costs – Transmission Production Plant - Pacific region to calculate the real dollar amounts for year 2014.

⁴⁰ Decision (D.)18-02-018.

⁴¹ Public Utilities Code Sections 454.51 and 454.52.

resource planning processes as a whole and identify the optimal mix of energy resources across the state needed for achieving its policy goals at the lowest cost possible.

2018 IRP Activities and Proceedings

On February 8th, 2018, the CPUC voted to establish IRP as a two-year planning cycle. The first year⁴² and in subsequent odd-numbered years, the CPUC will evaluate the appropriate GHG emission planning targets for the electric sector and LSE, and identify the optimal mix of system-wide resources capable of meeting these GHG planning targets. The second year and subsequent even-numbered years, the CPUC will consider the suite of actions each LSE proposes taking to meet these GHG targets. The CPUC will consider authorizing LSEs to procure resources within the next 1-3 years.

For IRP 2017-18, the CPUC Decision (D.18-02-018) recommends a statewide electric sector GHG Planning Target of 42 million metric tons (MMT) by 2030. The Decision also adopts an optimal Reference System Portfolio of energy resources to meet the 2030 GHG Planning Target, which indicates a need for approximately 10,200 MW of new supply-side renewable energy resources and 2,000 MW of new battery storage resources by 2030.

In 2018, each LSE will file individual IRPs that propose how it will meet the GHG Planning Target. LSE plans may include requests to procure new resources. The CPUC will aggregate individual LSE plans into a single combined portfolio and conduct production cost modeling to ensure that the aggregated plans meet both reliability requirements and GHG emissions targets. The CPUC will approve and/or modify individual LSE Plans and authorize any associated procurement activity, as necessary, to commence in the following 1-3 years.

In the 2017 IRP cycle the incremental revenue requirements of pursuing the optimal portfolio of resources identified by modeling was \$318 million/year⁴³. This is in addition to the projected increase of \$4,420 million/year resulting from already existing state mandates and policies, captured as baseline resources in the Reference System Plan. This incremental revenue requirement of the IRP Reference System Plan translates to an increase in average retail rates of 0.2c/kwh in real dollars in 2030 as compared to 2018 rates.

There is currently no formal procedural framework under which the IRP rate estimates are utilized to inform the GRC process or procurement authorization.

Energy Efficiency (EE)

Background and Status

Several pieces of energy efficiency-focused legislation were introduced in 2015 and are currently being implemented through CPUC direction: SB 350 calls for the doubling of energy efficiency by 2030; AB 802 focuses on methods of estimating baseline conditions and measuring programs based on metered

⁴² 2017 is considered the First Year.

⁴³ The IRP team has calculated the incremental revenue requirement forecasted through 2030 and translated the estimated value into SARs.

performance; and AB 1330 requires the CPUC to ensure sufficient funding is available to achieve state efficiency targets.

The CPUC regulates ratepayer-funded⁴⁴ energy efficiency programs managed by the utilities, other program administrators, and vendors. The programs are designed to overcome market barriers to adoption of high efficiency measures and to transform technology markets within California. Energy efficiency program administrators submit portfolio applications that are reviewed by Energy Division staff and rolled into the Public Purpose Program (PPP) revenue requirement. In order to ensure these funds are being used effectively, the CPUC evaluates all ratepayer-funded energy efficiency programs for cost-effectiveness. In 2017, efficiency program expenditures were \$1.1 billion with reported program electricity savings of 1,119 gigawatt-hours and natural gas savings of 23 million-therms.

Program Administrators (PA)⁴⁵ are required by the CPUC to contract with third parties for a portion of their energy efficiency portfolio activities. The rationale for third-party requirements has primarily been based on supporting innovation in program design, as well as the potential for cost savings through competition. In August 2016, the CPUC increased the required minimum percentage of third-party programs from 20% to 60% of total budgeted portfolio, to be completed by the end of 2020.⁴⁶ Previously, these third-party programs focused on hard-to-reach markets or regional needs. However, as trends in related proceedings move toward all-source solicitations and the CPUC continues to pursue program delivery cost savings and program design innovation, increasing the third-party requirements offered a logical strategy to achieve these goals.

The CPUC requires IOUs to implement certain statewide energy efficiency programs. Statewide programs are designed to be delivered uniformly throughout the four major IOU service territories. The reasoning behind such requirements is to take advantage of opportunities where customer or market actors for certain programs do not vary significantly across the state. Administering these programs on a statewide basis is intended to reduce transaction costs for administrators and implementers by allowing uniform incentive structures and reduction of administrative burden across IOU service territories. The statewide programs will be implemented once the business plans are approved.⁴⁷

2018 EE Activities and Proceedings

In January 2017, program administrators submitted their initial Rolling Portfolio filings⁴⁸, called business plans. The business plans are currently being reviewed by the CPUC and are pending approval. A CPUC decision on the approval of these filings is expected to be issued in 2018. In the interim before this decision

⁴⁴ These funds are collected as a portion of the public purpose program rate component.

⁴⁵ List of [Energy Efficiency Program Administrators](#).

⁴⁶ D.16-08-019.

⁴⁷ D.15-10-028, p. 42, states that “[Business plans] are major, new documents developed by each PA to describe its overarching strategy to support the state’s EE goals & objectives and plans for each customer sector, and to seek EE funding approval”.

⁴⁸ Rolling Portfolio filings are part of the process for regularly reviewing and revising energy efficiency program administrators’ portfolios.

is issued, energy efficiency program budgets are being held constant at 2015 budget levels. Rolling Portfolio energy efficiency goals for 2018 through 2030 were established by the CPUC in Fall 2017.⁴⁹

In January 2018, the CPUC addressed the third-party solicitation process for energy efficiency programs.⁵⁰ Stakeholder processes and filings to establish standard contract terms for these solicitations are still in process, with initial solicitations for these third-party programs expected to begin in 2019. While there may be high upfront transition costs associated with a third-party implementation approach, longer term savings for ratepayers are expected as third-party administration would effectively drive down long-term costs through competition. More specifically, the transition to a majority of third-party programs is expected to lower administrative costs and present more cost-effective programs and portfolios.

The CPUC issued a decision in March 2017, ordering the continued support and funding of the energy efficiency financing pilots administered by the California Alternative Energy and Advanced Transportation Financing Authority (CAETFPA). These financing pilots were designed to test new and innovative financing strategies with consumers, contractors, and lenders, to help leverage ratepayer and private financing to assist in achieving our aggressive energy efficiency goals. Successful financing pilots may help develop mechanisms that could effectively leverage private funds in support of energy efficiency program expansion. The CPUC expects that all financing pilot programs will be launched no later than December 31, 2019.

Demand Response (DR)

Background and Status

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

2018 DR Activities and Proceedings

In December 2017, the CPUC approved a 5-year budget of \$1.16 billion for utility-operated DR programs that will provide approximately 1,600 MWs of DR capacity by 2022.⁵¹ The costs of the programs will be recovered from ratepayers through retail electricity rates but were found to be cost-effective for PG&E and

⁴⁹ Decision (D.)17-09-025.

⁵⁰ Decision (D.)18-01-004.

⁵¹ D.17-12-003.

SCE (SDG&E's DR portfolio was found to be cost-ineffective. The Commission authorized SDG&E's DR programs because cost-effective measures made by SDG&E in past years had not fully gone into effect. The CPUC imposed certain conditions on SDG&E going forward, including reducing its portfolio costs by 10% and requiring SDG&E to show continued cost-effective improvements on a quarterly basis.) To the extent that DR programs are cost-effective, ratepayers benefit because alternative methods of serving their electricity needs are costlier.

Between April 2018 and April 2019, the CPUC will be undertaking three major DR activities that will have implications for future utility costs and rates:

- 1) The CPUC will finalize the DRAM pilot evaluation and decide on DRAM's future. The DRAM pilot was launched for many reasons, one of which was to determine if third-party DR providers could provide and operate demand response capacity as effectively as IOU-operated programs.
- 2) The CPUC will be considering pilots that are intended to increase DR participation in disadvantaged communities where a disproportionate amount of natural gas power plant capacity is located. By increasing access to DR in disadvantaged communities, residents of those areas will gain environmental and economic benefits. Authorization of the pilots is anticipated by mid-2018.
- 3) The CPUC has launched a Load Shift Working Group which is tasked with developing proposals for new bi-directional DR resources. These are resources that increase electricity consumption, to mitigate renewable over-generation on the grid. A report is due in January 2019.

Income Qualified Programs

Background and Status

California Alternative Rates for Energy (CARE)

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

Energy Savings Assistance Program (ESA)

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

Family Electric Rate Assistance (FERA)

The Family Electric Rate Assistance (FERA) program, provides families of three or more, whose household income slightly exceeds the CARE allowances, with a 12% discount on their electricity bill. The income limits of the FERA program range from 200% to 250% of the Federal Poverty Guidelines. Public Utilities

Code Section 739.1 (f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based upon their level of income and economic need.

Table 3 shows the 2017 spending for ESA, and CARE programs⁵²:

	2017 ESA Expenditures	2017 CARE Expenditures		
		Expenditures	Rate Discounts	Total
PG&E	\$121,041,750	\$13,168,911	\$ 643,538,184	\$656,707,095
SCE	\$59,321,530	\$6,706,298	\$375,043,839	\$381,750,137
SDG&E	\$17,360,035	\$5,923,625	\$ 114,029,348	\$119,952,973
SoCalGas	\$77,493,310	\$8,530,791	\$107,960,958	\$116,491,749
Statewide Total	\$275,216,625	\$34,329,625	\$1,240,572,329	\$1,274,901,954

Table 3: 2017 IOU ESA/CARE

2018 Income Qualified Programs Activities and Proceedings

CARE

For program years 2017-2020 the average annual budget for the CARE program is \$1.3 Billion. As of December 2017, approximately 4.5 million households were enrolled in CARE. The administrative costs of the program are expected to rise slightly as it becomes increasingly more difficult and expensive to connect with the “hard-to-reach households”, however, subsidies have remained relatively constant as post-enrollment verification policies have been put in place to ensure that only those truly qualified remain on the program. Significant cost and rate impacts are not anticipated in upcoming years because of these policies.

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

ESA

For program years 2017-2020 the average annual budget for the ESA program is \$450-\$500M and average household treatment goals are approximately 340,000 homes per year. ESA budgets have increased significantly over the years, resulting in potential cost and rate impacts, as new measures are added to the program and as it becomes increasingly more difficult and expensive to enlist “hard-to-reach households”.

In February 2018, SoGalGas and SCE filed Advice Letters seeking additional ESA program funds. A joint “mid-cycle” advice letter is also expected from the large IOUs due July 2018, potentially proposing program modifications and likely seeking additional funds to carry out the previous decision mandates.

⁵² The 2017 FERA spending is not available at the time of this report

FERA

The average annual budget for the FERA program is \$12.1 Million. As of December 2016, approximately 56,000 households were enrolled in FERA. No new activities or proceedings are planned in the next 12 months, and no significant growth resulting in cost and rate impacts in upcoming years is anticipated for the FERA program.

4. Current Trends and Rate Impacts

Community Choice Aggregators (CCAs)

Community Choice Aggregators (CCAs) are governmental entities formed by cities and counties to serve the energy requirements of their residents and businesses. CCAs allow cities and counties to combine the electricity demand of customers in their jurisdictions and procure electricity for them through their own generation or through the market. The procurement rates are not regulated by the CPUC and instead are regulated by the CCA following its own public process. The IOUs maintain the responsibility of providing transmission and distribution services, and continue to provide all metering, billing, and customer service to retail customers that participate in a CCA program. Utility customers within a CCA's boundaries become CCA customers by default, unless a customer elects to opt-out.

The CCA was authorized by AB 117 in 2002.⁵³ AB 117 requires the CPUC to “determine a cost-recovery mechanism to be imposed on the community choice aggregator to prevent a shifting of costs to an electrical corporation’s bundled customers.” Pursuant to these statutory requirements, in 2002 and subsequent years, the CPUC adopted a series of decisions on the policies and methodologies to assure that the CCAs did not shift costs between their customers and customers who remain with the utility (known as bundled customers). These decisions created the Power Charge Indifference Adjustment (PCIA). The CPUC sets the PCIA to recover the stranded resource procurement costs necessary to keep remaining bundled customers financially indifferent to the departure of customers taking CCA or other LSE service. Most of these costs are associated with long-term contracts the IOUs were directed to sign to meet renewable mandates and ensure they had sufficient resources to satisfy demand. However, any contracts less than one year are not captured by the PCIA and are borne by remaining bundled customers.

On June 29, 2017, the CPUC opened R.17-06-026 to review, revise, and consider alternatives to the PCIA. The calculation and allocation of costs is a central contested issue in R.17-06-026, and CPUC decisions in this proceeding will have significant rate impacts for both bundled and departing load customers. Both the CCAs and the IOUs argue that the current PCIA is flawed and fails to meet the statutory cost indifference requirements. The CCAs argue that the IOUs’ PCIA calculations are opaque and the IOUs fail to minimize the avoidable above-market costs by prudent resource management when customers depart from bundled service. The IOUs believe that the “administratively determined” market value of the contracts is significantly higher than the “true” market value, resulting in cost shifting to bundled customers. A decision on the proceeding is expected in July 2018.

CCAs have experienced rapid growth in recent years. Marin Clean Energy (MCE) was the first CCA to launch in 2010. From 2010 to 2015, two CCAs launched serving approximately 135,000 customer accounts statewide. From 2016 to 2017, 12 more communities launched or submitted CCA Implementation Plans to the CPUC. Based on Implementation Plans filed as of February 2018, it is estimated that in 2018 a total of

⁵³ Public Utility Codes 218.3, 331.1, 366.2, 381.1, and 394.25.

21 CCAs will be operational, with CCA programs in all three IOU territories. Based on 2018 initial load forecasts filed with the California Energy Commission in 2017, CCAs were expected to serve only 6.2% of the load in 2018. However, Implementation Plans filed as of December 6, 2017, indicate that 15.1% of the 2018 load is now expected to be served by CCAs.

Trends, Risks, and Rate Impacts of CCA Proliferation

Many communities throughout California are considering launching CCA programs or joining an existing CCA program. Long-term estimates of CCA growth are challenging to make because it is difficult to make assumptions about the outcome of local governments' deliberations. Many communities considering CCA programs cite regulatory uncertainty as a primary consideration in their decision-making process, particularly the PCIA proceeding, from which CPUC directives may result in policy updates or reform that would affect both CCA customer and bundled customer rates.

Residential Time of Use (TOU) Rates

In 2013, Assembly Bill 327 (AB 327) was enacted into law to reform residential rates⁵⁴ Residential Rate Reform⁵⁵, including the goal of default residential TOU by 2019, was set in Decision (D.)15-07-001 and provided direction to the three major electric IOUs regarding specific steps that must be taken to reform the residential rate design structure resulting in an envisioned end-state of default time of use (TOU) rates and an optional two-tier rate⁵⁶ Since then, CPUC has developed methodologies for setting the TOU periods, completed and reviewed the opt-in residential pilots, and as March of 2018, the default pilots are underway on all 3 IOU territories. However, PG&E and SCE have requested to delay the implementation of their default TOU to October 2020. A decision in consolidated Rate Design Window (RDW) applications A-17.12.11 on the new implementation timeline of the default TOU is expected in 2018.

TOU Opt-In Pilots

The opt-in pilots were designed to produce insight into customers' ability to accept and respond to TOU rates, principally by studying the load and bill impacts of implementing those rates. Another important aspect of the pilot design concerned assessment of any potential hardship impacts on certain customers.⁵⁷

The opt-in pilots were conducted from June 2016 to December 2017 across all three IOU service territories, testing eight different TOU rate options.⁵⁸ More than 50,000 households were enrolled and assigned to a treatment group on one of the TOU rates or a control group on the standard tiered rate. The eight TOU rates had varying time periods with late afternoon and evening peaks and a range of summer peak-to-off-

⁵⁴ Residential rate reform was only one part of AB 327.

⁵⁵ R.12-06-013.

⁵⁶ Decision (D.) 15-07-001; Residential default TOU rates implementation conditioned on meeting the requirements of Public Utilities Code Section 745

⁵⁷ Public Utility Code Section 745 requires that the CPUC ensure that any default TOU rate schedule does not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate regions.

⁵⁸ A ninth rate option was a complex, dynamic rate that SDG&E tested on a very small group of customers.

peak (POPP) price ratios from a modest 1.33:1 to a more robust 3.14:1.⁵⁹ The common peak hours across all eight tariffs were from 6 to 8 PM. While many pricing pilots and programs have been evaluated in the electricity industry, few if any have tested rates with peak pricing periods that extend well into the evening hours. Table 3 shows the results of peak-period load reduction for the eight different TOU rates.

Utility	Metric	Rate 1			Rate 2			Rate 3		
		Summer 2016	Winter 2016/2017	Summer 2017	Summer 2016	Winter 2016/2017	Summer 2017	Summer 2016	Winter 2016/2017	Summer 2017
PG&E	Peak Period Hours	4 PM - 9 PM			6 PM - 9 PM			4 PM - 9 PM		
	% Impact	5.8%	3.6%	5.3%	6.1%	3.6%	3.8%	5.5%	3.5%	5.6%
	Absolute Impact (kW)	0.06 kW	0.03 kW	0.06 kW	0.06 kW	0.03 kW	0.04 kW	0.06 kW	0.03 kW	0.06 kW
SCE	Peak Period Hours	2 PM - 8 PM			5 PM - 8 PM			4 PM - 9 PM		
	% Impact	4.4%	1.4%	3.6%	4.2%	2.0%	4.1%	2.7%	3.2%	4.0%
	Absolute Impact (kW)	0.06 kW	0.01 kW	0.04 kW	0.06 kW	0.02 kW	0.06 kW	0.03 kW	0.03 kW	0.05 kW
SDG&E	Peak Period Hours	4 PM - 9 PM			4 PM - 9 PM			N/A		
	% Impact	5.4%	2.3%	4.6%	4.6%	1.7%	4.1%			
	Absolute Impact (kW)	0.04 kW	0.02 kW	0.03 kW	0.04 kW	0.01 kW	0.03 kW			

Table 4: Weekly Peak Period Load Reduction⁶⁰

The key findings from the load impact analysis of the pilots are:

- Customers will respond to TOU price signals during evening hours and on weekends.
- Customers on TOU rates managed to reduce their loads during peak periods by about 4%-6% during summer months. For most rates, there were also small increases in off-peak electricity use, indicating that some load was shifted, not just reduced.
- Most TOU rates also produced overall reductions in electricity use.
- Peak-period reductions in winter were significantly less than in summer.
- Average monthly bill impacts for the TOU pilots were estimated for summer, winter and the full year. Key findings include the following:
 - Total annual bill impacts were very small at all three utilities, with average monthly reductions ranging between 0% and 2%. However, the annual bill impacts varied significantly by climate region and CARE/FERA status. Customers in hot climate regions were more likely to experience net annual bill increases, especially non-CARE/FERA customers.
 - Most customers saw very modest bill decreases on an annual basis, and seasonal volatility at PG&E and SCE is concerning, although it should be noted that, especially in hot climate regions, there is significant seasonal variation in bills even under the OAT due to seasonal variation in usage and the tiered rate structure.

⁵⁹ All POPP ratios based on Non-CARE/FERA Tier 2 tariffs as of March 1, 2017; see Appendix B in the California Statewide Opt-in Time-of-Use Pricing Pilot Final Report

⁶⁰ [Statewide Opt-In TOU Evaluation Final Report](#).

- For nearly all customer segments and all climate regions:
 - At PG&E and SCE, average monthly summer monthly bills were higher. Average monthly bill increases were between \$5 and \$40.
 - At PG&E and SCE, average monthly winter bills were lower. Average monthly bill reductions were between \$1 and \$12.
 - At SDG&E, customers had small bill impacts in both summer and winter months.

In addition to estimating load and bill impacts, key objectives for the TOU pilots included research questions that could only be addressed through customer surveys. Two surveys were conducted; the first after summer 2016 to evaluate pilot participants' experience on TOU rates over hot months, and a second after spring 2017 to evaluate experiences over cooler months. These surveys were designed to evaluate satisfaction with, perceptions about, understanding of and reported changes in behavior associated with different rate and other treatment options.

With the conclusion of the TOU Opt-in Pilots in December 2017, a final evaluation report will be issued in Spring 2018.

Default TOU Pilots

The default TOU pilots were designed to fine-tune customer transition to default TOU education and test system operability prior to full rollout of default TOU. For PG&E, customers selected for the pilot who do not opt-out will be defaulted onto one default rate; for SCE and SDG&E, customers selected for the pilot who do not opt-out will be defaulted onto one of two default TOU rates. These pilots commenced in Spring 2018 and are scheduled to conclude one year later.

All customers defaulted onto TOU rates will receive bill protection for the first full year on the new tariff.

5. Natural Gas

The CPUC regulates the natural gas utility services of more than ten million customers served by Pacific Gas & Electric, Southern California Gas, San Diego Gas & Electric, and several smaller utilities. Statute requires that the CPUC evaluate the reasonableness of rates and rate changes; provide advice on Core Transport Agent (CTA) rules⁶¹, and certificates of public convenience; and oversee the adoption of standards for bio-methane production. This mandate is reflected in the section's ongoing activities in formal rate case, cost allocation, bio-methane pilot project and safety-oriented proceedings. The section also administers to routine informal proceedings pertaining to rate and tariff changes

Elements

The natural gas utility costs covered here are composed of core procurement, gas system operations and customer service. Most of the details of these costs are addressed in the rate cases themselves (PG&E and Sempra's GRC and PG&E's GT&S). There are several other proceedings which have other costs that needed special attention.

Programs and Applications

➤ **PG&E Test Year 2017 General Rate Case (A.15-09-001)**

On May 11, 2017, the CPUC approved D.17-05-013 which determined the utility's gas distribution and electric system revenue requirements necessary to recover the capital investments, annual operations and maintenance expenses at the core of the utilities' operations. For 2017 gas distribution, the authorized revenue requirement decreased \$3 million from 2016 levels. The decision also authorized the post-test year revenue requirement for 2018 and 2019.

The gas distribution revenue requirement enabled PG&E to continue to upgrade its aging pipeline system and to improve its emergency response capabilities. First, PG&E received additional funding to transition from a 5-year to a 4-year leak survey cycle, to expand use of new surveyor technology, and to repair below-ground leaks. Second, PG&E received funding for new and replacement cathodic-protection systems and remote monitoring systems. Third, PG&E received additional funding for gas pipeline replacement and reliability, which includes replacing Aldyl-A plastic pipe, gas mains and the installation of additional emergency valves.

➤ **PG&E Gas Transmission and Storage Rate Case (A.13-12-012)**

In June 2016, the CPUC approved D.16-06-056, which funded new gas transmission and storage projects to mitigate safety risks from gas infrastructure. The safety mitigations included the hydro-testing program adopted from the Pipeline Safety Enhancement Plan and expanding the infrastructure replacement program

⁶¹ Core transport Agents (CTAs) procure gas for core customers such as residential and small commercial customers as an alternative to the utility

included in the Transmission Integrity Management Program. In the subsequent CPUC decision, D.16-12-010, the CPUC partially reduced the increase for residential customers by requiring that the utility's shareholders fund various safety related projects, as recompense for the San Bruno gas pipeline explosion. That decision adopted a revenue requirement of \$1.23 billion for 2018.

➤ **PG&E Test Year 2019 Gas Transmission and Storage Rate Case (A.17-12-009)**

In November 2017, PG&E filed an application to set its revenue requirement and rates for the utility's gas transmission and storage system for 2019 through 2021. For 2019, PG&E is requesting the CPUC to approve a revenue requirement of \$1.5 billion, a \$289 million increase from 2018. The work that the funding would be used for includes hydro-testing the utility's pipelines to ensure that they can withstand operating pressure, upgrading pipelines to inspect pipelines using advanced in-line inspection devices to measure wall strength, and to implement new gas storage regulations adopted by the Department of Oil, Gas and Geothermal Resources.

PG&E has also proposed in the proceeding to significantly reconfigure its gas storage system. The utility seeks to close two existing gas storage facilities, Los Medanos and Pleasant Creek, and to substantially reduce the capacity of MacDonald Island, its largest gas storage facility. The impact of this proposal on the reliability of PG&E's gas system and ability to serve its customers is a key consideration. The application is currently pending and the CPUC will evaluate PG&E's proposals to ensure they are just and reasonable and in the public interest.

➤ **OIR to Reduce Natural Gas Leakage (SB 1371; R.15-01-008)**

On June 17, 2017, the CPUC approved D.17-06-015 establishing best practices and reporting requirements for the Natural Gas Leak Abatement Program in consultation with the California Air Resources Board, pursuant to Senate Bill (SB) 1371 (Leno, Chapter 525, Statutes of 2014), as set forth in PU Code Section 975, 977, 978. Actions taken in the decision support California's goal to reduce methane emissions 40% below 2013 levels by 2030 (SB 1383, Lara, Chapter 395, Statutes of 2016). The CPUC and ARB continue to collaborate on policies to achieve the state's greenhouse gas emission reductions goals.

According to PU Code Section 977 (d), the CPUC shall consider "the impact on affordability of gas service for vulnerable customers as a result of incremental costs of compliance with the adopted rules or procedures." Consistent with the statute, cost and cost-effectiveness are important considerations as it would not be in the public interest for the CPUC to require actions of gas utilities that result in unjust or unreasonable rates. The decision acknowledges that given the numerous unknowns associated with a new program, there is not yet enough quantifiable information to evaluate the cost-effectiveness of the program. Therefore, the decision required the utilities to provide forecasts for the 2018 and 2019 incremental costs associated with the Natural Gas Leak Abatement Program.

➤ **Sempra Application to recover recorded costs for PSEP 2 (A.16-09-005)**

On September 2, 2016, Sempra filed an application to recover costs attributed to the implementation of the Pipeline Safety Enhancement Program Phase 2 (D.14-06-007). The program was forecasted to cost \$195 million, with approximately \$134M earmarked for capital and \$61M to O&M, resulting in a revenue requirement of \$71 million. Sempra is seeking cost recovery for 26 pipeline projects, 15 bundled valves projects, and 2 methane sensing equipment pilot projects. A proposed decision is scheduled to be issued on the 2nd quarter 2018.

➤ **Sempra application for revenue requirement associated with PSEP (A1703021 PSEP 3)**

On March 30, 2017 Sempra filed an application for a new revenue requirement associated with PSEP. The program was forecasted to cost approximately \$255 million. The forecasted expenditures were to be \$197.5 million in capital and \$57 million in O&M, resulting in a cumulative forecasted 2019 revenue requirement of \$45 million. Sempra is seeking preapproval for certain Phase 1B and Phase 2A PSEP projects. In addition, Sempra requested modification to subdivide existing Phase 1 balancing accounts (SEEBAs and SECCBAs) into Phase 1A and Phase 1B, and the creation of two balancing accounts for Phase 2 projects.

➤ **Rulemaking OIR to implement Dairy Biomethane Pilots (SB 1383; R 17-06-015)**

SB 1383 (2016) required that the CPUC develop “at least five” dairy biomethane projects to demonstrate renewable natural gas project interconnection to the natural gas common carrier pipeline system. Rulemaking 17-06-015 opened to develop the parameters for these pilot projects. The utilities and the Selection Committee collaborated to develop the pilot project solicitation document which was published on March 7, 2018. Final selection of the pilot projects will occur in the fourth quarter of 2018, and construction of these pilot projects will likely commence in 2019 at the earliest.

The CPUC was also required to look into natural gas pipeline injection gas quality standards under AB 1900 (2013). Additionally, SB 2313 (2016) required that the CPUC establish a natural gas pipeline interconnection incentive program and consider ways to increase the availability of biomethane. AB 840 (2016) required that the California Department of Science and Technology perform an independent study of the known literature on biomethane for pipeline injection across the United States to advise the Commission on gas quality issues such as heating value and siloxane content. A future proceeding will open to formally address natural gas pipeline injection gas quality standards and other issues to further develop the renewable natural gas industry in California.

6. Discussion and Conclusion

Increasing retail competition and changing market dynamics under the Cost of Service model of the ratemaking environment make the CPUC's mandate to manage costs and rates increasingly challenging. This section of the report synthesizes the cumulative "big picture" findings, trends, and rate impacts across the major programs previously discussed to evaluate options to be investigated as improved measures for containing costs, limiting rate increases, and taking progressive action toward DER market development. This synthesis recognizes the limitations and challenges associated with cost-of-service rulemaking in its current form and identifies opportunities for exploration of changes to this model.

Cost Containment and the DER Action Plan Nexus

The overarching objective of this report is strategic, and forward thinking about the role of ratesetting in promoting a robust and equitable DER marketplace. As part of this mandate, we want to better examine the connection between utility cost management, rate design, and DER investment opportunities, while evaluating improved cost-effectiveness and increasing value to our consumers through rate options, distribution services, and alternatives to traditional utility earnings and incentives models.

In fulfilling one of the milestones of the ratesetting track of the DER Action Plan, the Commission's Energy Division convened an "Advanced Rates Forum" (Forum) in December 2017 to begin discussing and addressing issues, challenges, and potential areas of future reform in non-residential rate design. In the subsections that follow, we tie together key insights from the Forum with proposed actions for limiting utility costs and highlight areas of ongoing inquiry that can facilitate our long-term ratemaking goals and mandates.

TOU Incentives for Managing Grid Costs at Peak

Through the DER Action Plan, the CPUC promotes cost-effective DR and TOU programs, which work together to deliver grid benefits by reducing peak demand, avoiding higher capacity costs, and better utilizing grid assets. The CPUC recognizes that continued growth in peak demand occurs even as overall energy consumption is flat or declining, and that moderating the peak would slow the upward trajectory of rates over time. Indeed, these conditions have resulted in a declining load factor,⁶² making the electric grid less efficient.

Storage has potential to address the declining load factor, and moderate future rate increases. By reducing peak load and mitigating the duck curve⁶³, the electric grid will require fewer kW of generation, transmission, and distribution capacity per kWh of energy demanded, meaning lower capacity costs over time. Time-differentiated rates are essential to incentivize both customer investments in storage and the grid benefits of

⁶² Load factor is the ratio of average usage over the peak usage. By definition this is a number between zero and one. Load factor is a measure of system efficiency; the higher the load factor, the more efficient is the grid.

⁶³ See [CAISO Duck Curve](#).

that storage. The CPUC has begun to mandate or encourage more energy storage on the grid and adopt rate designs that discourage peak energy use as well as encourage customers to invest in and operate storage to provide grid benefits. For example, the legislatively-authorized Self-Generation Incentive Program now emphasizes incentives for customer-owned storage.

In accordance with CPUC policy, non-residential customers have gradually, over the past decade, been placed on mandatory TOU rates and default critical peak pricing (“CPP”). However, time-differentiation is only applicable to the generation component, and many small and medium customers face generation rates that are only weakly time-differentiated. Furthermore, legacy rate designs for medium and large customers generally rely heavily on non-time-differentiated demand charges.⁶⁴ Demand charges may incentivize customer investments in energy storage, but they do not necessarily incentivize the operation of that storage to reduce system peak demand. As such, “coincident” demand charges at peak are a far better tool than “non-coincident” demand charges for encouraging beneficial storage investment and operations, as well as encouraging peak demand reduction generally.

The TOU opt-in pilot studies showed that customers react to TOU pricing favorably, and shift their electricity loads to take advantage of lower prices. The load shift magnitude may depend on the magnitude of peak to off peak ratios, and with a continuum of rates, from simple to complex, customers would be motivated to take advantage of lower prices at off peak (and super off-peak) periods, potentially aiding absorption renewable over-generation. Consistent with the DER Action Plan’s vision, grid efficiency and cost containment benefits can be maximized through increased use of time differentiated rates, reduction of non-time differentiated rate elements and appropriate incentives for storage implementation and usage.

Capital Bias and the “Perverse Incentive”

All the programs, rate trends, and cost management opportunities addressed in the foregoing chapters have a cumulative impact on rates and bills in the face of the “perverse incentive” of utilities to prioritize long term capital expenditures in physical assets. Indeed, perhaps the strongest factor elevating rates is the natural quest for accruing earnings from capital investment, an inherent bias in cost of service regulation driving operational decisions that might not always be in the best interest of customers when it comes to furnishing innovative new services at reasonable rates. This tendency is likely one of the underlying reasons for the increase in utility requests for capital spending in transmission and distribution in recent years: to compensate for declining generation earnings.⁶⁵

As many other industries continue to invest heavily in third-party services, utilities naturally favor infrastructure assets that can be amortized in their rate base and earn a return. For instance, while most

⁶⁴ Demand charges are expressed in dollars per kilowatt, as opposed to energy charges which are in dollars per kilowatt-hour. Generally, residential and small commercial customers do not pay demand charges.

⁶⁵ Distribution O&M has been increasing, mostly as the results of replacing and modernizing infrastructure, and the legislative mandates including but not limited to GHG emission reductions, RPS, transportation electrification, and energy efficiency. Moreover, the ERRRA pass-through portion of the revenue requirements has also been increasing, especially in distribution and transmission components. Over the last decade, on an annual average base, the transmission component of the IOUs’ total authorized revenue requirement increased approximately 35% for SCE, 11% for PG&E, and 36% for SDG&E.

other industries are driven toward investments in cloud-based IT platforms, California IOUs are incentivized to continue investing in potentially less efficient and more expensive traditional hardware (servers) and software to maximize their authorized rate of return on the physical asset.

A recent article by AEEI highlights utilities' dilemma in seeking to increase investment in third-party services for customers while trying to maximize earnings for shareholders:

Over the long term, however, services that can improve the utilization of, defer, or replace capital investments may have the effect of reducing opportunities for utilities to generate earnings. Because many new technologies are offered only as a service, utilities may be discouraged from using them. Realizing that both customers and utilities stand to benefit from equalizing the earnings opportunities between traditional capital solutions and service solutions that reduce capital investment needs, several state PUCs have explored or implemented mechanisms to compensate for the bias toward capital investments that is inherent in cost-of-service regulation.⁶⁶

While the CPUC has made some inroads into evaluating alternative forms of equalizing earnings opportunities between capital and service solutions in the DER incentive plus framework, there is still plenty of room for progress through directed research. For example, recent market surveys⁶⁷ indicate that utility executives are by and large aware of the challenges they face regarding load defection, and want to continue investing in grid modernization efforts, DERs, and retail services.

The CPUC's adopted "DER Adder" enables the utility to receive 4% of the total cost of the periodic payments for the service solution as an added incentive to compensate for avoided earnings on infrastructure assets. However, the rate of return on traditional rate-based assets accrues to shareholders in larger quantities and potentially over longer time horizons, thereby remaining the paramount driver of utility investment decisions.

The AEEI article explores proposals for capitalizing DERs and other Non-Wires Alternatives (NWAs) or prepaid contracts⁶⁸ for putting service-based assets into rate base and/or supplementing earnings in an effort to put them en par with traditional COSR capital expenditures.⁶⁹ According to Navigant Research,⁷⁰ NWA is "An electricity grid investment that uses non-traditional T&D solutions, such as distributed generation, energy storage, energy efficiency demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level."⁷¹ Such alternatives to the traditional earnings model continue to be investigated as part of the proceedings included in the CPUC's DER Action Plan, however,

⁶⁶ "Utility Earnings in a Service Oriented World: Optimizing Incentives for Capital- and Service-Based Assets", Advanced Energy Economy Institute, January 30, 2018 (AEEI article), at iv.

⁶⁷ See "Utility Dive Report: The State of the Electric Utility 2016.", Utility Dive.

⁶⁸ Prepaid contracts would treat expenses as capital expenditures to be amortized over time.

⁶⁹ AEEI article at iv.

⁷⁰ Navigant Research is a market research and consulting team that provides in-depth analysis of global clean technology markets.

⁷¹ See "[Non-Wires Alternatives: What's up next in utility business model evolution](#)". Utility Dive, July 12, 2017.

we envision opportunities for greater coordination and research into additional options with our rates and modeling staff.

Conclusion

The mission and focus of this report is to continue researching potential improvements in the traditional cost-of-service regulatory model and to enhance coordination while achieving the shared objectives of PU Code Section 913.1 and the DER Action Plan. Throughout the report, there are a number of areas of additional research and inquiry that are highlighted and should be prioritized in order to minimize cost and maximize the value of services provided to ratepayers by utilities.

In accordance with the DER Action Plan's directives, and to better manage rates, the Commission must be strategic and forward-looking in facilitating a prosumer culture that is not simply mindful of cost minimization, but that also values maximization through sufficient rate options and DER investment opportunities. This means promoting new and innovative ways to partially mitigate utility capital bias in the rate case process through innovative new incentives that foster the rollout of DERs and NWAs, for which utilities recover the cost of their investments (i.e. based on prepaid services), and are incentivized to keep the service cost lower than the cost of capital.

Additionally, it is critical to take a closer look at utility earnings across major program areas and determining the necessity and feasibility of certain infrastructure investments related to timing and scope of such capital programs. Facilitating the grid of the future and a more dynamic market of widening retail choice will therefore necessitate additional information about proposed utility incentives that complement the cost-of-service regulatory model to attempt to mitigate earnings erosion as DERs and related services expand. However, we must also assess the extent to which IOUs might be overearning and unnecessarily driving costs and rates upward due to the tendency to seek a higher volume of profits through overcapitalization. Rather than assume that any new incentive models for an expanding array of prosumer services must necessarily compensate the utilities for avoided earnings through capital outlays, the Commission has the tools to evaluate the financial health of the utilities and to manage earnings and DER market development directly.

As set forth as part of the DER Action Plan vision, customers can be more empowered and engaged by rates and tariffs that enable them to shift loads and potentially achieve incremental bill savings. A growing menu of rate options that will enable utilities to personalize services and provide the correct price signals to consumers is essential to maximizing value by the tailored needs of market segments. Managing cost is only one part of the equation; creating additional value through services solutions and access to emerging in-home technologies and a smarter grid is a bigger challenge that can only be achieved through market segmentation, optimal rate design, and favorable DER investment opportunities and value propositions.

Evaluating cost and rate trends in a dynamic industry and regulatory environment should not be limited to the production of this annual legislative report, as it requires continuous examination, prioritization, and strategic planning by CPUC staff across silos in an integrated and proactive fashion.

Appendix A

IOU Summaries on Limit Cost and Rate Increases

Public Utilities Code Section 9.13.1 mandates that the IOUs study and report on measures that they recommend be undertaken to limit costs and rate increases. IOUs' submissions include a list of each utility's proceeding before the CPUC and its expected impact on rates, as well as a description of each utility's expected upcoming revenue requirements. The IOUs responded to CPUC's request for this year's report and their recommendations are summarized below.

Along with this report, each of the IOU's submissions can be accessed via the CPUC website⁷².

Pacific Gas and Electric Company (PG&E)

In late 2016, PG&E announced a goal to reduce overall annual expenses by \$300 million. The areas identified for reduction were focused largely on back-office functions that would not adversely affect operational safety and reliability. They include: material and contract spending, and employee-related expenses, including travel etc.

PG&E stated its commitment in controlling costs, but that many factors that affect rates are outside of its control. PG&E thinks that the current rate design architecture is inadequate because of its reliance exclusively on undifferentiated volumetric rates and that current rates serve the interest of special interest rather than all ratepayers. The IOU asserts that rates should be designed to charge customers based on the cost to serve them, while any compensation provided to customers that causes rates to differ from cost of service should be independent from the cost-based rate to ensure it is both transparent and measurable.

PG&E then proposes a future rate architecture that allows unbundled, differentiated rates to enable separation of payment for the grid, customer services, and the actual electrons, while continuing to fund mandated energy policies and ensuring customers pay their fair share of any historic costs PG&E has incurred on their behalf. Some of the suggestions include:

- Customers should pay full retail rates for all energy and capacity consumed
- Customers should separately be paid the fair value of the generation they sell back to the utility, based on the utility's avoided energy costs.
- Customers should be paid for the long-term value of avoided grid costs provided by installation of their system.
- If policy makers choose to continue to incentivize PV equipment installations beyond the avoided costs savings provided, such compensation should be quantified and separately tracked as a policy cost that is borne by all customers and not by-passable.
- Fixed Charges recovered through volumetric rates.

⁷² <http://www.cpuc.ca.gov/General.aspx?id=6442457129>

- Seasonal bill volatility.

PG&E also states that as part of its effort to curb rate increases, it limits the number of rate adjustments made throughout the year, to two or three times per calendar year (January and March, and occasionally a change later in the year for electric rate changes). For gas rate changes, it files monthly changes to the gas commodity rate and seeks an annual rate change to reflect changes in gas transportation and Public Purpose Program costs.

Southern California Edison Company (SCE)

SCE reassures its commitment to fulfilling its core mission of providing safe, reliable, affordable and clean electricity to its customers through operating and service excellence across all business and functional areas. However, SCE recognizes there are cost components that are driven by market forces outside of its control which directly impacts rates. SCE identified the following three areas in its core business that directly affect and cause unexpected rate increases:

1. Regulatory and legislative requirements, such as Demand Response, Energy Efficiency, Solar Initiatives, Self-Generation and Low-Income programs
2. Infrastructure replacement requirements
3. Power procurement function.

SCE states that it relies on a policy of marginal cost-based allocation in order to control the level of costs allocated to the various customer classes. That is, more revenue is recovered from customer classes that contribute to a higher level of the utility's cost of service and less is recovered from customer classes that have a lower cost impact to the utility. SCE states that this policy helps to limit the burden of any particular costs on a given customer class and helps to direct a larger allocation of those costs to customer classes who are driving the marginal expenditures. It also states that it uses hedging tools to reduce the variability in cost of power to its customers.

SCE believes that market solutions will tend to lead to lower cost solutions for ratepayers and recommends finding the least cost paths to meet current and future customer needs. Some of its other suggestions are as follows:

- Aligning incentives with desired outcomes
- Expanding the geographic scope of new renewable development to incorporate out-of-state projects that help meet California's energy needs
- Transitioning from substantial cost shifting between customer groups, e.g. NEM
- Development of a modernized grid that can monitor and control the two-way flow of power in the distribution system
- Consistent policies related to the expanding role of distributed energy resources as well as expanding distribution infrastructure capability to integrate these resources.

San Diego Gas and Electric Company (SDG&E)

SDG&E believes that the increasing complexity of ratemaking makes balancing customer choice and opportunities to save critical to providing rates that send accurate price signals to customers for the benefit of the grid and all customers. SDG&E identifies the state's GHG reduction policy as the major driver of rate increases and cost shifting for electric utility customers. The firm believes that the Renewables Portfolio Standards (RPS) goals of 33% by 2020 included a cost limitation provision that is set at a level that prevents disproportionate rate impacts to its customer classes.

SDG&E affirms its continued effort to move toward rates that reflect accurate prices, and incentives or subsidies that are direct and transparent. And that it is creating an effective platform for ensuring ratepayers have full access to competitive customer choices in a manner that is economically efficient and beneficial to all customers.

SDG&E believes that achieving the state's energy policy goals in a sustainable manner requires growth not be dependent upon flawed rate design which creates cost shifts and results in indirect and at times unintended subsidies. The IOU also believes that the policies around departing load customers in its territory causes rate increases resulting from costs of long-term procurement contracts that are shifted to the remaining customers.

SDG&E recommends the following policies for limiting costs and rate increases while meeting the state's energy and environment goals for reducing GHG:

- Accurate price signals: Providing customers with accurate price signals means that utilities charge for the services they provide, and rates are designed to cover costs on the same basis by which they are incurred. And by sending customers clear price signals regarding the cost of electricity and the cost of using the electric grid for the services they receive.
- Transparent incentives: Incentives or subsidies that have been deemed necessary to further public policy objectives are separately and transparently identified. Cost-shifting is exacerbated with incentives that are buried in rates and not transparently identified.
- Customer options: SDG&E believes that a critical aspect of SDG&E's policy framework is to balance the needs of customers while still providing a cost-based rate structure.
- Transition paths to minimize impacts and inform customers: SDG&E believes that implementing rate design changes in transitional phases:
 1. helping to minimize customer impacts
 2. providing the best opportunity for customers to progressively gain greater control and become more engaged and informed about available choices.

Southern California Gas Company (SoCalGas)

SoCalGas states that it is working proactively to lower gas costs and participates in interstate pipeline rate cases that ensure just and reasonable transportation costs, and that it prioritizes operational efficiency and

cost containment, in addition to safety and reliability. SoCalGas believes that rates should be based on the costs incurred to provide ratepayers with safe and reliable gas service and had proposed changes to align residential rates more closely with the underlying costs of serving residential customers. It stated that some key drivers that affect customers' rates fall outside of its control, and these include: gas commodity prices, actual sales volumes, weather, natural disasters, interest rates, economic and demographic growth, permitting process delays, and compliance with new environmental regulations and CPUC requirements.

The IOU states that it seeks to minimize the impact of rate adjustments when they are made by phasing in impacts to avoid rate shock whenever possible. It makes monthly changes to the gas commodity rate which is based on the monthly cost of gas. It also files for an annual gas transportation and Public Purpose Program surcharge rate change every January. In addition, it submits any required rate update filings within the year in response to specific CPUC decisions that affect its revenue requirement.

SoCalGas' recommendations center on factors largely out of the scope of its control, but the IOU stated that these factors are expected to have a significant impact on utility costs and resultant customer rates in the near- to medium-term. Some of the suggestions include:

- Developing a list of cost-effective, technologically feasible mitigation activities and technologies that help achieve methane emission reductions in top emissions source categories (Natural Gas Leak Abatement).
- Development and promotion of Efficient Combined Heat and Power (CHP).
- Encouraging use of fuel cell technology at residential level for generation and water heating.
- Flexibility to implement energy efficiency and greenhouse gas programs.
- Introducing Performance-Based Incentives for Utilities.

The utility believes that the costs associated with reduction of GHG emissions, adoption of advanced technologies, and expenditures on public purpose programs mandated by law place upward pressure on utilities' rates. The IOU wants more flexibility in implementing these mandates and requirements to achieve lower costs for all its customers.