1. Opening Comments

In response to the Energy Division's Data Request dated January 8, 2019, SCE is providing the following information to assist the Commission in preparing its Senate Bill (SB) 695 annual report to the Governor and Legislature. Specifically, SB 695 requires:

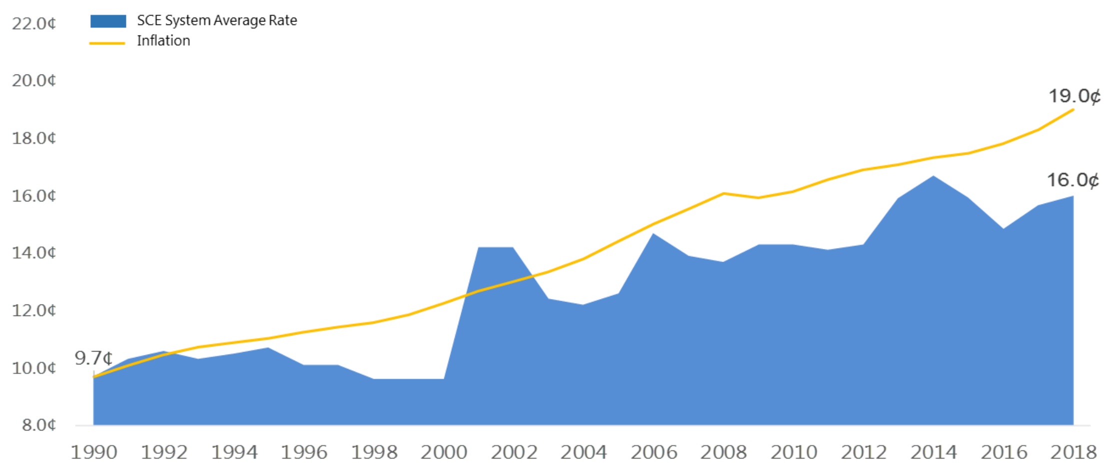
> "that by May 1, 2010, and by May 1 of each year thereafter, the commission also report to the Governor and Legislature with its recommendations for actions that can be undertaken during the upcoming year to limit cost and rate increases, consistent with the state's energy and environmental goals, including the state's goals for reduction in emissions of greenhouse gases. The bill would require the commission to annually require electrical and gas corporations to study and report to the commission on measures that they recommend be undertaken to limit costs and rate increases."

The information provided includes SCE's overall rate policy, a discussion of SCE management's policies and practices to control costs and rate increases for customers, and a discussion of SCE's policies and recommendations for limiting rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases. SCE also provides a brief overview of additional programs the company is proposing in the short term to minimize wildfire risk. Appendix A to this Report describes SCE's revenue requirements and provides an outlook for pending revenue requirement and rate changes from May 1, 2019 to April 30, 2020.

2. Overall Rate Policy

SCE's overall rate policy is to fully recover the authorized revenue requirement in an equitable manner while considering public policy objectives. SCE designs its rates to meet the traditional design objectives (e.g., recovery of authorized revenue requirement, rates based on cost of service, and rate stability) while supporting the various public policy objectives established by the legislature and regulators. By recovering its authorized revenue requirement through cost based rates, SCE can properly operate, maintain and invest in its distribution system, provide reliable power as needed, and meet customer service needs as they arise. Recovering these costs equitably from customers ensures that those customers who are more costly to serve pay appropriately higher rates. Rates that are equitable and cost-based also send the correct price signals to customers and prevent uneconomic decisions regarding energy usage.

Figure 1 below shows a comparison of SCE's actual System Average Rate as compared to what the average rate would have been if it had changed commensurate with the Consumer Price Index.[1]



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[1] Consumer Price Index for All Urban Consumers Los Angeles-Long Beach-Anaheim, CA (1982-84=100) IHS MARKIT ECONOMICS December 2018 Forecast Source: Bureau of Labor Statistics

The costs of service, which are comprised of capital and expenses associated with replacing or maintaining an additional unit, differs by rate class, and makes up one of many principles underlying SCE's practice of revenue allocation and rate design. The marginal cost of service is used as the basis for revenue allocation between the rate classes, and for rate setting as the foundation of retail rates.

In revenue allocation, once the marginal costs of service and marginal cost revenue responsibility[2] have been determined by rate class, the authorized revenue requirement, or the amount of revenues to be recovered from each class for operational or program capital and expenses, is then allocated to each class based on the proportion of marginal cost revenue responsibility that is attributed to each class. Generally the class average rate is higher than the system average rate when the rate class in question contributes to a higher proportion of costs relative to the system average and to other classes.

In revenue allocation, a collaring mechanism is used to limit total change in revenue responsibility allocated to each rate class, based on adopted marginal costs. The collaring mechanism applies a percentage change cap and floor to the amount of change a rate class can expect to see in revenue allocation from one General Rate Case cycle to the next. Although the collar mechanism obscures the direct impact of cost based revenue allocation, the mechanism restricts the magnitude of change in revenue allocated to each

[2] Marginal cost revenue responsibility is determined by applying the billing determinants to rates set at the marginal costs levels for each class.

rate class and consequently has the effect of stabilizing rates and providing a measure of affordability.

In addition to introducing a collar mechanism to moderate any changes in average class rates due to revised revenue allocation, other measures are taken to address structural deficiencies in rates to improve bill stability and affordability in certain segments. For example, the baseline allowance for basic residential customers was increased from 53% of average usage in each climate zone to 60%, increasing the amount of monthly usage (kWh) considered to be reasonable energy needs and that qualify for the lower first tier rate. Additionally, efforts are underway to increase customer enrollment in the Family Electric Rate Assistance (FERA) Program, which offers households with three or more persons living at 250% of the Federal poverty Level an 18-percent discount off the bill.

Tables 1 and 2, shown in nominal and real values respectively, provide a view of trends in rates for SCE's different customer classes. Data through 2018 are based on billed operating revenues and sales. Data for 2019 is based on forecast revenues and sales. Table 3 provides an alternative view of this data by expressing this information as a percent of the system average rate.

Table 1

Historical Average Rates by Rate Group (Nominal ¢/kWh) Based on Recorded Revenue and Sales
2019 Average Rates by Rate Group Based on Forecasted Revenue and Sales

Bundled Service

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	[1]
Domestic	11.4	11.4	11.5	13.0	13.5	12.8	12.5	12.9	15.7	15.3	15.0	15.2	15.5	15.6	15.9	16.7	16.4	16.6	16.2	16.9	16.8	18.0	
TOU-GS-1	12.1	12.1	12.0	16.2	17.5	15.8	14.8	15.2	17.6	17.6	17.0	16.9	17.5	17.3	17.6	17.5	18.3	18.0	15.9	16.7	16.7	17.3	
TC-1	7.3	7.4	7.4	10.3	13.5	12.4	12.0	11.5	13.4	13.5	13.8	14.5	15.8	15.9	15.6	16.9	18.6	19.0	17.9	18.1	18.2	18.9	
TOU-GS-2	9.9	10.2	10.1	13.2	15.5	14.1	13.3	13.5	15.6	14.3	14.3	14.8	15.7	15.4	14.9	16.2	17.4	17.3	15.9	16.8	15.8	17.3	
TOU-GS-3	9.7	8.9	10.2	13.1	14.7	13.0	11.8	10.8	13.6	14.2	14.1	14.3	13.7	13.2	12.7	14.3	15.9	15.8	14.2	15.1	13.2	15.4	
Sm. and Medium Comm.	10.3	10.5	10.4	13.7	15.8	14.4	13.5	13.6	15.6	14.9	14.7	15.0	15.5	15.2	14.9	16.0	17.2	17.1	15.5	16.4	15.3	16.8	
TOU-8-Sec	8.1	8.2	8.7	12.2	14.3	12.6	11.2	11.3	13.2	12.5	12.4	12.7	13.1	12.7	12.3	13.7	15.0	14.9	12.7	13.7	11.9	13.8	
TOU-8-Pri	7.2	7.4	7.9	10.9	13.0	11.5	10.3	10.7	12.6	11.9	11.8	11.7	11.8	11.5	10.9	12.1	13.2	13.1	11.1	12.0	10.1	12.4	
TOU-8-Sub	4.9	5.1	5.7	8.3	9.4	8.4	7.4	7.5	9.1	8.3	8.1	7.9	8.0	7.6	7.0	8.1	9.1	9.1	6.5	8.0	5.9	8.4	
Large Power	6.8	7.1	7.7	10.6	12.6	11.2	9.9	10.0	11.8	11.1	10.9	10.9	11.1	10.6	10.1	11.7	12.9	12.8	10.6	11.7	9.6	11.9	
PA-1	12.8	12.1	12.1	14.3	15.3	14.9	14.0	15.1	18.2	16.9	17.5	17.8	19.4	19.7	18.5	12.3	14.4	13.8	13.0	14.2	13.7	14.2	[2]
PA-2	8.7	8.5	8.7	10.7	11.3	10.5	10.4	10.7	12.8	12.5	12.8	13.1	14.8	14.9	14.2								
AG-TOU	7.4	6.9	7.5	9.4	10.1	9.0	8.5	8.5	10.0	9.6	9.7	9.9	10.9	10.3	9.3	12.0	13.2	12.3	10.4	11.3	10.9	11.7	[3]
TOU-PA-5	6.9	6.3	7.0	8.8	9.4	8.2	7.8	7.8	9.4	9.0	8.9	9.1	9.9	10.3	9.1								
Ag. and Pumping	8.8	8.5	8.7	10.6	11.1	9.9	9.4	9.5	11.3	10.9	10.8	11.0	12.0	11.6	10.8	12.1	13.8	13.1	11.9	12.9	12.5	13.1	
St. and Area Lighting	17.0	14.1	13.9	15.8	17.3	15.5	14.7	14.0	15.3	16.9	17.9	18.7	19.0	18.9	18.1	18.2	18.7	19.1	18.0	18.4	18.2	18.5	
STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.2	12.7	13.3	11.7	12.5	10.8	14.1	
STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.9	12.5	13.0	11.1	12.2	11.6	13.5	
STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	7.9	9.3	9.5	5.9	7.9	7.2	8.3	
Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9.1	10.1	10.5	7.3	9.0	8.1	9.9	
Total System	9.6	9.9	10.0	12.5	14.0	12.9	12.2	12.4	14.6	14.0	13.8	14.0	14.4	14.2	14.1	15.0	15.7	15.6	14.4	15.4	14.1	15.9	

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2019 ERRA Application. Excludes PUCRF Revenues.
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[3] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)

Note: During the Enery Crisis of 2001-2002, the Commission adopted a 3 ¢/kWh surcharge. The majority of the impact of this increase went to Large Power and Commercial customers. SCE, over time, is driving towards getting each group to pay its cost to service.

Southern California Edison Company
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Table 2

Historical Average Rates by Rate Group (Nominal ¢/kWh) Based on Recorded Revenue and Sales
2019 Average Rates by Rate Group Based on Forecasted Revenue and Sales

Bundled Service

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	[1]
Domestic	17.5	17.2	16.7	18.3	18.5	17.1	16.2	15.9	18.6	17.5	16.6	17.0	17.1	16.7	16.7	17.4	16.8	17.0	16.2	16.4	15.7	16.4	
TOU-GS-1	18.6	18.1	17.5	22.7	23.9	21.1	19.1	18.7	20.9	20.2	18.9	18.8	19.3	18.6	18.6	18.2	18.8	18.3	15.9	16.3	15.6	15.7	
TC-1	11.2	11.1	10.7	14.5	18.4	16.6	15.5	14.3	15.9	15.5	15.3	16.2	17.4	17.1	16.4	17.6	19.1	19.4	17.9	17.6	17.1	17.2	
TOU-GS-2	15.3	15.4	14.6	18.6	21.2	18.8	17.2	16.7	18.4	16.4	15.9	16.6	17.4	16.5	15.7	16.9	17.9	17.6	15.9	16.4	14.8	15.8	
TOU-GS-3	14.9	13.4	14.9	18.4	20.2	17.3	15.2	13.3	16.2	16.3	15.6	15.9	15.1	14.2	13.4	15.0	16.4	16.1	14.2	14.7	12.3	14.0	
Sm. and Medium Comm.	15.8	15.8	15.1	19.3	21.7	19.2	17.5	16.8	18.4	17.1	16.3	16.8	17.1	16.3	15.7	16.7	17.7	17.4	15.5	15.9	14.3	15.3	
TOU-8-Sec	12.4	12.3	12.7	17.1	19.5	16.8	14.4	14.0	15.6	14.4	13.8	14.2	14.4	13.6	13.0	14.2	15.4	15.2	12.7	13.4	11.2	12.5	
TOU-8-Pri	11.1	11.0	11.5	15.3	17.8	15.3	13.3	13.2	14.9	13.7	13.1	13.0	13.0	12.3	11.4	12.6	13.6	13.4	11.1	11.7	9.4	11.3	
TOU-8-Sub	7.6	7.7	8.2	11.7	12.8	11.2	9.6	9.3	10.8	9.6	9.0	8.8	8.8	8.2	7.4	8.4	9.4	9.3	6.5	7.8	5.5	7.6	
Large Power	10.4	10.7	11.2	14.8	17.2	15.0	12.8	12.4	13.9	12.7	12.1	12.2	12.2	11.4	10.6	12.2	13.3	13.0	10.6	11.4	9.0	10.8	
PA-1	19.7	18.2	17.5	20.1	20.9	19.8	18.0	18.6	21.5	19.4	19.4	19.9	21.4	21.1	19.5	12.8	14.8	14.0	13.0	13.8	12.0	12.9	[2]
PA-2	13.4	12.8	12.7	15.0	15.4	14.1	13.5	13.2	15.1	14.3	14.2	14.6	16.3	16.1	15.0								
AG-TOU	11.3	10.3	10.8	13.2	13.8	11.9	11.0	10.5	11.8	11.0	10.7	11.1	12.0	11.1	9.8	12.5	13.6	12.5	10.4	11.0	12.0	10.7	[3]
TOU-PA-5	10.5	9.4	10.2	12.3	12.9	11.0	10.1	9.7	11.1	10.4	9.8	10.1	11.0	11.1	9.6								
Ag. and Pumping	13.6	12.8	12.7	14.9	15.1	13.2	12.2	11.8	13.4	12.5	11.9	12.3	13.3	12.5	11.3	12.6	14.2	13.4	11.9	12.6	11.7	11.9	
St. and Area Lighting	26.1	21.2	20.2	22.2	23.6	20.7	19.0	17.3	18.1	19.4	19.8	20.9	21.0	20.3	19.1	19.0	19.2	19.5	18.0	17.9	17.0	16.8	
STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11.7	13.1	13.6	11.7	12.2	10.1	12.9	
STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	12.4	12.8	13.2	11.1	11.9	10.9	12.3	
STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	8.3	9.6	9.7	5.9	7.6	6.7	7.6	
Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	9.4	10.4	10.7	7.3	8.7	7.6	9.0	
Total System	14.8	14.9	14.6	17.5	19.2	17.2	15.7	15.3	17.2	16.0	15.3	15.6	15.8	15.3	14.8	15.6	16.1	15.9	14.4	14.9	13.2	14.4	
CPI Deflator (LA Area)	1.54	1.50	1.45	1.41	1.37	1.33	1.29	1.23	1.18	1.15	1.11	1.12	1.10	1.07	1.05	1.04	1.03	1.02	1.00	0.97	0.94	0.91	[4]

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2019 ERRA Application. Excludes PUCRF Revenues.
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[3] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)
[4] Estimated figure

Note: During the Enery Crisis of 2001-2002, the Commission adopted a 3 ¢/kWh surcharge. The majority of the impact of this increase went to Large Power and Commercial customers. SCE, over time, is driving towards getting each group to pay its cost to service.

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Table 3

Historical Average Rates by Rate Group (Nominal ¢/kWh) Based on Recorded Revenue and Sales
2019 Average Rates by Rate Group Based on Forecasted Revenue and Sales

Bundled Service

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	[1]
Domestic	118%	115%	114%	104%	96%	99%	103%	104%	108%	109%	109%	109%	108%	110%	113%	111%	104%	106%	112%	110%	119%	113%	
TOU-GS-1	125%	122%	120%	130%	125%	122%	121%	123%	121%	126%	123%	120%	122%	122%	125%	117%	116%	115%	110%	109%	119%	109%	
TC-1	76%	74%	74%	83%	96%	96%	99%	93%	92%	96%	100%	103%	110%	112%	111%	113%	118%	122%	124%	118%	129%	119%	
TOU-GS-2	103%	103%	100%	106%	110%	109%	109%	109%	107%	103%	104%	106%	110%	108%	106%	108%	111%	111%	110%	110%	112%	109%	
TOU-GS-3	100%	90%	102%	105%	105%	100%	97%	87%	94%	102%	102%	102%	95%	93%	91%	96%	101%	101%	98%	98%	94%	97%	
Sm. and Medium Comm.	107%	106%	104%	110%	113%	111%	111%	110%	107%	107%	107%	107%	108%	107%	106%	107%	110%	109%	107%	107%	108%	106%	
TOU-8-Sec	84%	83%	87%	98%	102%	98%	92%	92%	90%	90%	90%	91%	91%	89%	87%	91%	95%	95%	88%	89%	85%	87%	
TOU-8-Pri	75%	74%	79%	87%	92%	89%	84%	86%	86%	85%	86%	83%	82%	81%	77%	81%	84%	84%	77%	78%	71%	78%	
TOU-8-Sub	51%	52%	56%	67%	67%	65%	61%	61%	62%	60%	59%	56%	56%	54%	50%	54%	58%	58%	45%	52%	42%	53%	
Large Power	70%	72%	77%	85%	90%	87%	82%	81%	81%	79%	79%	78%	77%	75%	72%	78%	82%	82%	73%	76%	68%	75%	
PA-1	133%	122%	120%	115%	109%	115%	115%	122%	125%	121%	127%	127%	135%	138%	131%	82%	92%	88%	90%	93%	97%	90%	[2]
PA-2	90%	86%	87%	86%	80%	82%	86%	86%	88%	89%	93%	93%	103%	105%	101%								
AG-TOU	76%	69%	74%	75%	72%	69%	70%	69%	69%	69%	70%	71%	76%	73%	66%	80%	84%	78%	72%	74%	78%	74%	[3]
TOU-PA-5	71%	63%	70%	70%	67%	64%	64%	63%	65%	65%	64%	65%	69%	73%	65%								
Ag. and Pumping	92%	85%	87%	85%	79%	76%	77%	77%	78%	78%	78%	79%	84%	82%	77%	81%	88%	84%	83%	84%	89%	83%	
St. and Area Lighting	176%	142%	138%	127%	123%	120%	121%	114%	105%	121%	130%	134%	132%	133%	129%	122%	119%	122%	125%	120%	129%	117%	
STANDBY/SEC	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	75%	81%	85%	81%	81%	76%	89%	
STANDBY/PRI	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	79%	80%	83%	77%	80%	83%	85%	
STANDBY/SUB	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	53%	59%	61%	41%	51%	51%	53%	
Standby	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	60%	65%	67%	51%	58%	57%	62%	
Total System	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2019 ERRA Application. Excludes PUCRF Revenues.
[2] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands < 200 kW (PA-1 and PA-2 mapped to TOU-PA-2)
[3] 2012 GRC Phase 2 Rate Group Change for Ag/Pumping Customers with Demands ≥ 200 kW (AG-TOU and TOU-PA-5 mapped to TOU-PA-3)

Note: During the Enery Crisis of 2001-2002, the Commission adopted a 3 ¢/kWh surcharge. The majority of the impact of this increase went to Large Power and Commercial customers. SCE, over time, is driving towards getting each group to pay its cost to service.

3. Management Control of Rate Components

SCE requests in CPUC and FERC General Rate Cases[3] funding to operate its generation, transmission and distribution businesses in order to provide safe, reliable, and affordable electric service to all customers in its service territory. Based on the funding authorized by the Commission, SCE has the ability to manage those core utility businesses. However, funding has not always been adequate to fulfill all infrastructure replacement requirements on the company's planned schedule and in the short term SCE will require funding above both requested CPUC and authorized FERC General Rate Case levels to respond the new higher levels of wildfire risk.

Another portion of SCE's total revenue requirement is associated with its power procurement function. Based on a set of assumptions that reflect regulatory and legislative requirements, SCE requests funding to procure enough power to meet its customers' load. Although there are procurement cost components that are driven by market forces outside of SCE's control, such as natural gas prices, SCE has been given some authority by the CPUC to use hedging tools to reduce the variability in cost of power to its customers. A third category of costs are associated with policies driven by Commission and the Legislature for funding programs such as Demand Response, Energy Efficiency, Solar Initiatives, Self-Generation and Low Income programs. In compliance with these policies, SCE makes initial requests for funding these programs but the final authorized funding amounts are determined by the Commission based on its policy objectives. Finally, there are costs included in the total revenue requirement that are fully outside of SCE's management control such as DWR Power and Bond Charge

[3] SCE's FERC transmission revenue requirement is currently established through a formula rate mechanism.

revenue requirements and other costs whose magnitude are prescribed by the legislature or a regulatory agency (e.g., while the requirement in Assembly Bill (AB) 1890 to collect revenue for the California Energy Commission to fund its Renewable, and Research, Development and Demonstration programs expired at the end of 2011, the CPUC issued a decision that continues funding for RD&D programs through 2020).

As previously stated, SCE relies on a policy of marginal cost based allocation in order to control the level of costs allocated to the various customer classes. 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. In other circumstances, the allocation of costs may be governed by statute or Commission order.

SCE is committed 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.

4. Utility's Policies and Recommendations For Limiting Costs and Rate Increases While Meeting the State's Energy and Environment Goals for Reducing Greenhouse Gases

Wildfire risk in SCE's territory has increased dramatically in recent years due to climate change, drought, and other factors such as a growing wildland-urban interface and the significant build-up of fuel, including on federal and state forest lands. By the summer of 2018, SCE recognized that wildfire risk had increased to the point where the safety of our communities required additional and immediate measures to address this new higher level of wildfire risk resulting in SCE's Grid Safety and Resiliency Program

(GSRP) Application (A.18-09-002). SCE also filed its 2019 Wildfire Mitigation Plan (WMP), consistent with Senate Bill 901 (SB 901), enacted in 2018, to implement measures that will further harden SCE's electric system against wildfires and improve system resiliency.

While the California wildfire threat is currently SCE's operational focus, California is continuing its leadership in addressing climate change and air pollution. The state's approved greenhouse gas (GHG) goals call for a 40 percent reduction in GHG emissions from 1990 levels by 2030 and an 80 percent reduction by 2050. Air quality goals include a 90 percent reduction in emissions of nitrogen oxides from 2010 levels in some of the state's most polluted areas by 2032. Meeting environmental goals of this magnitude will require fundamental changes to infrastructure and transportation and, at the same time, can also help the California economy by creating new jobs. In November of 2017 SCE published its Clean Power and Electrification Pathway, which is an integrated approach to reduce GHG emissions and air pollution by taking action in three California economic sectors: electricity, transportation and buildings. It builds on existing state policies and uses a combination of measures to produce the most cost-effective and feasible path forward among the options studied.

By 2030, it calls for:

- An electric grid supplied by 80 percent carbon-free energy;
- More than 7 million electric vehicles on California roads; and
- Using electricity to power nearly one-third of space and water heaters, in increasingly energy-efficient buildings.

However, California's policy goals cannot be achieved by the electric sector alone which is already at the forefront of California's fight against climate change and today accounts for only 19 percent of the state's GHG emissions. Moreover, the electric sector continues to deal with industrywide changes that may compromise its ability to influence climate change policies. As more and more customers in the utility's service territory opt to procure their generation through Community Choice Aggregators (CCA) that can negotiate pricing with large generators, IOUs contend with CCA customers on the assessment of Power Charge Indifference Adjustment (PCIA) charge without distorting rates paid by bundled customers. The transportation sector (including fuel refining) and fossil fuels used in space and water heating now produce almost three times as many GHG emissions as the electric sector and more than 80 percent of the air pollution in California. Therefore, SCE believes a three-pronged approach is needed to achieve California's environmental goals, namely, 1) continue carbon reduction in the electric sector, by increasing energy efficiency, providing 80 percent carbon-free energy through large-scale resources and distributed energy resources, 2) accelerate electrification of the transportation sector, including placing at least 7 million light-duty passenger vehicles on the roads and supporting a transition to zero-emission trucks and transit, and 3) increase electrification of buildings, by targeting to electrify nearly one third of residential and commercial space and water heaters. Accomplishing these tasks, just as was the case with achieving the goals of California's landmark carbon reduction bill Assembly Bill (AB) 32, will require careful thought, broad market solutions, and flexibility so as to avoid undue cost implications and to continue California's role as a model for others to follow in responsible GHG reductions.

California's environmental policies need to be coordinated to be effective. Simultaneously pursuing GHG reduction, local air emissions reductions, water use restrictions, and land use restrictions requires a comprehensive and coordinated process. Otherwise, resources might be wasted and we also risk the reliability and affordability of electricity.

Generally, market solutions will tend to lead to lower cost solutions to meet policy goals. As such, the goals should be broadly defined, as opposed to mandates to procure specific technologies. Furthermore, the ability to maintain a reliable electric grid should be part of the original debate in developing State policies, rather than an afterthought whose solutions either conflict with other State mandates, or receive broad opposition from parties who are not knowledgeable or concerned about maintaining a reliable grid.

Broader markets will lead to lower costs. As we develop and implement market solutions, we should seek to achieve broader market solutions wherever possible, if we want to minimize the rate impacts of achieving State environmental policy goals. Out-of-state resources should be allowed to help California meet its goals if they are lower cost. This means allowing any GHG reduction means to be used, including broad use of offsets, as long as they can be appropriately verified.

Aligning incentives with desired outcomes will lead to greater success in reaching targets. California is the national leader in energy efficiency, due in no small part to its decoupling of utility revenues from electricity sales. This was the result of recognition that entities will always be resistant to acting against their own interests. The converse of this example is to impose a mandate with serious financial consequences such that it provides an incentive to reach the goal at any cost. Such structures are not conducive to reaching State environmental goals at least cost.

Achieving environmental goals without undue rate impacts also requires flexibility: the flexibility to relax time constraints on achieving goals if doing so prevents undue cost implications; the flexibility to change rules when we learn that there were unintended adverse consequences; the flexibility to adopt new ideas that will help achieve our environmental and cost goals, even if those ideas arise after our programs are already in place; the flexibility to adapt California's programs to National programs as they emerge.

Some of the key actions that the CPUC, Legislature, and Governor can do to help manage and minimize rate increases in the future are described below. These generally fall into the categories of finding least cost solutions to meeting GHG reduction goals, maintaining fair and efficient rate structures for customers, and effectively adapting to changing technologies, particularly those impacting the distribution grid, as advances in this space are potentially rapidly transforming how customer needs will be met in the future.

In the area of renewable procurement, providing as much flexibility to use least cost options is critical to ensuring the clean power used to serve future customer needs is affordable. This means limiting the technology based targets and restrictions sometimes used to satisfy the needs of subsets of the renewable community, appropriately expanding the geographic scope of new renewable development to incorporate out of state projects that help meet California's energy needs while displacing higher emitting out of state resources in the process, recognizing that many new renewable resources are connecting on the distribution grid that needs to be modernized, and achieving renewable expansion goals at least cost by relying on markets without artificial distinctions such as the interconnection points to determine the mix of future renewable development.

Another critical factor in achieving GHG reduction policies in the State without an undue cost burden on customers is the transition away from substantial transfers of costs in rates between customer groups. For example, the current Net Energy Metering tariff continues to result in substantial shifting of costs to non-participating customers, who are paying for the grid being used by net energy metering customers. It is a regressive subsidy that could lead to excessive rates for non-participating customers with unintended consequences such as less electrification and economic activity shifting to other jurisdictions where such impacts don't exist or are not so prominent.

As more and more new resources seek to connect to the distribution grid and want to provide and be compensated for services, the need for a modernized grid that can monitor and control the two-way flow of power in the distribution system will be critical to maintaining, and hopefully enhancing, the reliability and resiliency of the grid. To prepare for this changing environment where GHG abating technologies such as photovoltaic generation, energy storage, demand side management, and transportation electrification play an increasing role in meeting future customer needs, California must have the electrical infrastructure capable of meeting these needs. The CPUC, Legislature, and Governor's office must have consistent policies related to the expanding role of distributed energy resources as well as expanding distribution infrastructure capability to integrate these resources.

Finally, utilities must be vigilant in finding least cost paths to meet current and future customer needs. Maintaining its focus on Operational Excellence is one of the means employed by SCE to control its budgets and revenue requirements. Operational Excellence is the framework SCE management has established to deliver on our mission of providing safe, reliable, and affordable power for our customers. Operational Excellence builds off our core value – Continuous Improvement. SCE has rededicated itself to exploring every opportunity to improve the operations across the company. Continuous improvement means improving everything from the way we set and communicate goals approved by our Board of Directors to challenging all employees to find ways of becoming more efficient and effective in their daily jobs. It also means being self-critical in all efforts across the company and asking ourselves what we do, why we do it, and whether there are ways to do it more efficiently. This involves looking at other companies to see if we are performing up to industry best practices. We describe this process as: Measure, Benchmark, Improve, and Repeat. Repeat is critical, as the industry will continue to improve thus always setting a higher bar for SCE.

As seen in the Figure 1 above, SCE's system average rate is above peak levels on a nominal basis largely due to higher sales expected for behind-the-meter residential solar customers. However, on a real dollar basis, SCE's 2019 system average rate remains below peak rates in the early 2000's.

APPENDIX A

1. Revenue Requirements Effective January 1, 2019

a. Summary of Revenue Requirements by Rate Component/Key Category

The table below shows SCE's Total System Revenue Requirements and Bundled System Average Rate for Bundled Service customers by key category as of January 1, 2019.

As of January 1, 2019	Total System		Bundled SAR
Rate Component	$ Millions	%	c/kWh
Generation	5,351	45.0%	7.5
New System Generation	398	3.4%	0.5
Distribution (inc. GHG revenue)	4,318	36.3%	5.6
Public Purpose Programs	475	4.0%	0.6
Nuclear Decommissioning	4	0.0%	0.0
FERC Transmission	962	8.1%	1.2
DWR Power and Bond	371	3.1%	0.5
Total	11,880	100.0%	15.9

b. <u>Summary of Revenue Requirements by Proceeding</u>

The table below shows SCE's Total System Revenue Requirements by proceeding as authorized by the Commission and FERC effective as of January 1, 2019, including the sources of the data.

Southern California Edison Company
January 1, 2019 Consolidated Revenue Requirements In Rate Levels By Proceeding
TOTAL SYSTEM
($000)

	Column 1 Revenue Requirement Component	Column 2 Revenue Rqmts January 1, 2019 Rate Levels	Column 3 Percent of Total Revenue Requirements	Column 4 Authority For Change
1.	**ERRA FORECAST PROCEEDING**	**4,575,548**	**38.5%**	D.17-12-018
2.	**GRC PROCEEDING**			
3.	Base Revenue Requirement	5,640,432	47.5%	D.15-11-021, Advice 3514-E
4.	Tax Refund (2012 - 2014 Incre. Repair Deductions)	5,936	0.0%	Advice 3368-E
5.	Pole Loading & Deteriorated Poles Balancing Account	(43,999)	-0.4%	D.15-11-021
6.	Tax Accounting Memorandum Account (TAMA)	(226,879)	-1.9%	D.15-11-021, Advice 3610-E-A
7.	Pension/PBOP/Medical Balancing Accounts	(43,791)	-0.4%	D.15-11-021
8.	Non-utility Affiliate Credits	(11,261)	-0.1%	D.15-11-021 (FF&U rate change)
	SUBTOTAL	**5,320,438**	**44.8%**	
9.	BRRBA/CARE/PPPAM/NDAM	58,988	0.5%	D.15-10-037
10.	Self-Generation Incentive Program (SGIP)	56,648	0.5%	D.17-04-017, Advice 3592-E
11.	CA Solar Initiatives/MASH/SASH	6,070	0.1%	D.15-01-027, Advice 3212-E
12.	Low Income Programs (ESAP & CARE)	70,355	0.6%	D.16-11-022, Resolution E-4885
13.	Statewide ME&O	8,753	0.1%	D.16-09-020, Advice 3677-E
14.	Charge Ready Phase 1 Pilot	2,844	0.0%	D.16-01-023, Advice 3709-E
15.	Demand Response Programs	43,351	0.4%	D.17-12-003
16.	EPIC - RD&D and Renewables	70,651	0.6%	D.18-01-008
17.	Energy Efficiency	315,893	2.7%	Advice 3465-E-B
18.	Energy Efficiency Incentives	17,191	0.1%	Res. E-4897, Advice 3655-E
19.	FERC Base Transmission	1,056,724	8.9%	FERC Docket No. ER18-169
20.	FERC Transmission Balancing Accounts	(94,964)	-0.8%	Docket No. ER19-220, ER18-1207-000 and ER19-219
21.	SUBTOTAL	**1,612,505**	**13.6%**	
22.	**DWR**	**371,286**	**3.1%**	D.18-12-040
23.	**TOTAL REVENUE REQUIREMENT**	**11,879,777**	**100.0%**	

c. Description of Rate Components and Revenue Requirements

SCE recovers its revenue requirements through the following retail rate components: Generation, Cost Responsibility Surcharge (CRS), New System Generation, Distribution, Public Purpose Programs, Nuclear Decommissioning and Federal Energy Regulatory Commission (FERC) jurisdictional Transmission. In addition, SCE is authorized to include on customer bills the DWR Power Charge and Bond Charge on behalf of the California Department of Water Resources (DWR).

a. **Generation** – Through the Generation rate component, SCE recovers the costs of its generation portfolio which include the cost of SCE's Utility Owned Generation (UOG) consisting of the fuel, base O&M and capital-related revenue requirements associated with its nuclear, gas, and hydro plants. In addition, SCE recovers all of its purchased power costs required to meet its load not met by its UOG.[4] The purchased power costs include the costs of Qualifying Facilities (QFs), and all other bilateral contracts that SCE has entered into since 2003 when the company was authorized to resume the power procurement function and make purchases and sales through the wholesale markets. The impact of renewable contracts entered into to meet the Renewables Portfolio Standard and Greenhouse Gas costs will be reflected in generation rates.

b. **Cost Responsibility Surcharge** – Through the CRS, which includes the Competition Transition Charge (CTC) and Power Charge Indifference Adjustment (PCIA) rate components, SCE recovers from customers that have elected to purchase their generation service from other providers (e.g. Direct Access (DA) customers and Community Choice Aggregation (CCA)) the above-market costs of the SCE generation portfolio that was procured prior to their departure. The revenue generated from the CRS reduces the generation costs that must be collected from SCE's bundled service customers so that they remain indifferent to the departure of those customers, and are not burdened with paying for the above-market costs of the procurement SCE had planned and incurred to serve the departed customers.

c. **New System Generation** – Through the New System Generation (NSG) rate component, SCE recovers the costs of those "new generation" assets that the Commission

[4] By the end of 2011, all of the DWR purchased power contracts that were allocated to SCE's bundled service customers expired. Therefore, beginning in 2012, SCE is supplying 100% of its bundled service customers' generation requirements.

has required SCE to procure in order to maintain system reliability for the benefit of all customers. The NSG revenue requirement includes the contracted procurement costs less the value of the energy produced. The net cost, or capacity cost, is recovered from all customers who benefit from the additional system capacity provided by the new generation, including DA and Community Choice Aggregation (CCA) customers.

d. **Distribution** – Through the Distribution rate component, SCE primarily recovers its base distribution O&M costs and its capital-related revenue requirement. In addition, the Commission has authorized SCE to recover its Charge Ready Program funding, Demand Response program funding, California Solar Initiative program funding, and some Energy Efficiency incentives through the Distribution rate component. The Commission has authorized SCE to provide the California Alternate Rate for Energy (CARE) discount to the income-qualified customers through the Distribution rate component. As a result of the Commission's decision in the GHG Revenue Rulemaking (R.11-03-012) and the Residential Rate R.12-06-013, SCE returns proceeds that result from the cap-and-trade market to residential customers through a semi-annual Climate Credit (i.e. a credit included on customer's bills) and through the distribution rate component to certain small business customers.[5]

e. **Public Purpose Programs Charge (PPPC)** – Prior to 2012, SCE recovered the legislatively mandated Public Goods Charge funding for the California Energy Commission administered Research Development and Demonstration and Renewable

[5] Proceeds are also returned to certain large customers defined as Energy-Intensive Trade-Exposed through an annual bill credit or check.

programs, Self-Generation Incentive Program funding, plus a portion of the SCE-administered Energy Efficiency programs, through the PPPC. The funding for these three programs expired on December 31, 2011 as mandated by P.U Code 399. The Commission issued a decision in December 2011 that continued this funding in 2012 through 2020 using the name Electric Program Investment Charge. In addition, through the PPPC rate component SCE recovers additional program funding authorized by the Commission for Procurement Energy Efficiency, and Low-Income programs. The Commission has authorized SCE to recover the costs of the CARE program including the discount provided to CARE-eligible customers from all non-CARE customers through the PPPC.

f. **Nuclear Decommissioning** – Through the Nuclear Decommissioning rate component, SCE recovers the customers' portion of the Nuclear Decommission Trust funding authorized by the Commission to be used to decommission SCE's share of the San Onofre and Palo Verde Nuclear Generating Stations. In addition, SCE recovers costs associated with the storage of spent nuclear fuel through this rate component.

g. **FERC-Jurisdictional Transmission** – SCE's FERC-jurisdictional transmission rate is comprised of four components: 1) Base Transmission which recovers the O&M and capital-related revenue requirement associated with transmission assets under ISO operational control and subject to FERC's jurisdiction; 2) flow-through to customers of transmission revenues generated through wholesale customers' use of the transmission system; 3) Reliability Services costs related to contracts signed by the California Independent System Operator (CAISO) with certain generators needed to maintain system reliability; and 4) Transmission Access Charge which reflects the net contribution by SCE's customers to the transmission revenue requirements of all participating transmission owners in the CAISO system.

As SCE moves forward to meet the State's renewable goals, it must construct new transmission lines to bring the renewable generation from out-lying areas to the load centers. The construction of additional transmission facilities will increase SCE's FERC-jurisdictional Transmission rates.

h. **DWR Power Charge and Bond Charge** – In early 2001, as the result of the energy crisis and AB1X, DWR entered into long term power contracts that were necessary to meet the state's Investor Owned Utilities' (IOUs') net short requirements. The Commission authorized SCE to recover on behalf of DWR, the revenue requirement associated with these contracts through the DWR Power Charge. As mentioned above, all of the remaining DWR contracts that had been allocated to SCE's bundled service customers expired as of December 31, 2011. In addition, in order to recover the costs DWR incurred in early 2001 to purchase energy on behalf of IOUs' customers from dysfunctional wholesale markets which were initially financed by the State's General Fund, the Commission authorized SCE to bill the DWR Bond Charge. All of the revenues associated with the DWR Power and Bond Charges are collected by SCE and passed on to DWR.

Since 2001, DWR was required to maintain high levels of operating reserves such that DWR would have enough cash on hand to fulfill its contractual obligations in case power prices skyrocketed. Since the power contracts have expired, DWR no longer is required to maintain this level of reserves and has returned them to customers. Therefore, the Commission-allocated DWR Power Charge Revenue Requirement to SCE's bundled service customers in 2019 is minimal. In 2019, the DWR Bond Charge remains at the 2018 level of approximately $0.005/kWh.

2. Sales Forecast

a. Provide your utility's publicly-available authorized load / sales forecast data effective January 1, 2019. Please provide the source of this data.

SCE has not received approval of its 2019 ERRA Forecast proceeding (A.18-05-003), which also adopts the 2019 sales forecast, however the total sales forecast for 2019 is shown below with comparisons to prior years. 2017 is recorded while 2018 and 2019 are forecast.

(GWh)

Line Description	2017	2018	2019
1. **Total Retail Sales (@meter)**	85,602	83,302	81,970

b. Provide your utility's publicly-available actual load / recorded sales data for calendar year 2018. Please provide the source of this data.

Recorded at meter sales for 2018 was 85,276 GWh and the source is SCE's internal billing system, however this will be made public in SCE/EIX's 2018 Annual Report (SEC 10-K filing)

Outlook from May 1, 2019 to April 30, 2020

Southern California Edison Company
SB 695 Report To Energy Division
Year: 2019

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Estimated/Requested Dollar Amount ($millions)		Description	Impacted Rate Component
				2019 RRQ	2020 RRQ		
2018 GRC	A.16-09-001	9/1/16	1/1/20	$5,965	$6,468	2020 Requested Attrition year increase in O&M and capital revenue requirement	Generation, Distribution, and New System Generation
2020 ERRA Forecast (Includes GHG Costs and Revenue Return)	TBD	6/1/19	1/1/20	$4,867[1] est.	TBD	Recovery of estimated fuel and purchased power costs	Primarily Generation, but also New System Generation, Distribution and Public Purpose
Wildfire Expense Memorandum Account (WEMA)	TBD	TBD 2019	TBD	TBD	TBD	Recovery of costs recorded in the WEMA related to wildfire insurance, legal fees and claims	Distribution
Grid Safety & Resiliency Program	A.18-09-002	9/10/18	1/1/20	$67M	$151M	Wildfire risk mitigation measures	Distribution
BPA/SCE Carbon-Free Energy Product Pilot Transaction	TBD	Expected April 2019	Mid 2019	$1-1.5M est.	$1-1.5M est.	Premium for EE-like power imported from BPA	Generation
San Joaquin Valley Disadvantaged Communities Pilot	D.18-12-015	9/10/18	1/1/19	$5.1 est.	$5.1 est.	Replacement of propane and wood burning appliances with electric (SCE $15.4M over three years)	Public Purpose
Energy Savings Assistance Program (ESA) 2020-2024 Funding	TBD	June 2019	1/1/20	$70	TBD	Low Income Energy Efficiency (ESA) and CARE Administration funding for the 2020-2024 period	Public Purpose
Clean Energy Optimization Pilot	A.18-05-015	5/15/18	1/1/20 est.	-	$5M	Approx. $20M over four years	Funding through GHG revenue set asides (distribution)
AB 1082/1083	A.18-07-022	1/30/18	1/1/20	$0.89M	$3.6M	EVSE infrastructure at schools and parks	Distribution
Charge Ready Phase 2	A.18-06-015	June 2018	1/1/20	$1.8	$57.8	EVSE infrastructure and ME&O	Distribution
Catastrophic Event Memorandum Account (CEMA)	Application	TBD 2019	1/1/20	$49.5	TBD	CEMA recorded activity for 2017	Distribution

Cost of Capital	TBD	April 2019	1/1/20	-	TBD	Filing pursuant of D.17-07-005	Generation, Distribution, and New System Generation
FERC Formula Rate Change	N/A (Advice Letter)	Nov. 2018	1/1/19	$1,163	TBD	Base Transmission Revenue	Transmission
FERC Transmission Balancing Accounts	N/A (Advice Letter)	May (TACBAA) and Oct. 2019 (RSBAA and TRBAA)	6/1/19 and 1/1/20	($95)	TBD	FERC-related Balancing Accounts	Transmission
DWR – Power and Bond Charge	TBD	TBD	1/1/20	$371	TBD	Bond Charge	Generation

1/ At the time of this submission SCE had not received a final decision in its 2019 ERRA forecast application (A.18-05-003), therefore, this amount is based on SCE's Comments on the 2019 ERRA Forecast Proposed Decision with updated balances through December 2018, plus the 2018 ERRA balancing account December ending balance of $815 million ($825 million with FF&U) separately litigated in SCE's 2018 ERRA Trigger application (A.18-11-009).