1. Opening Comments

In response to the Energy Division's Data Request dated January 25, 2018, 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."

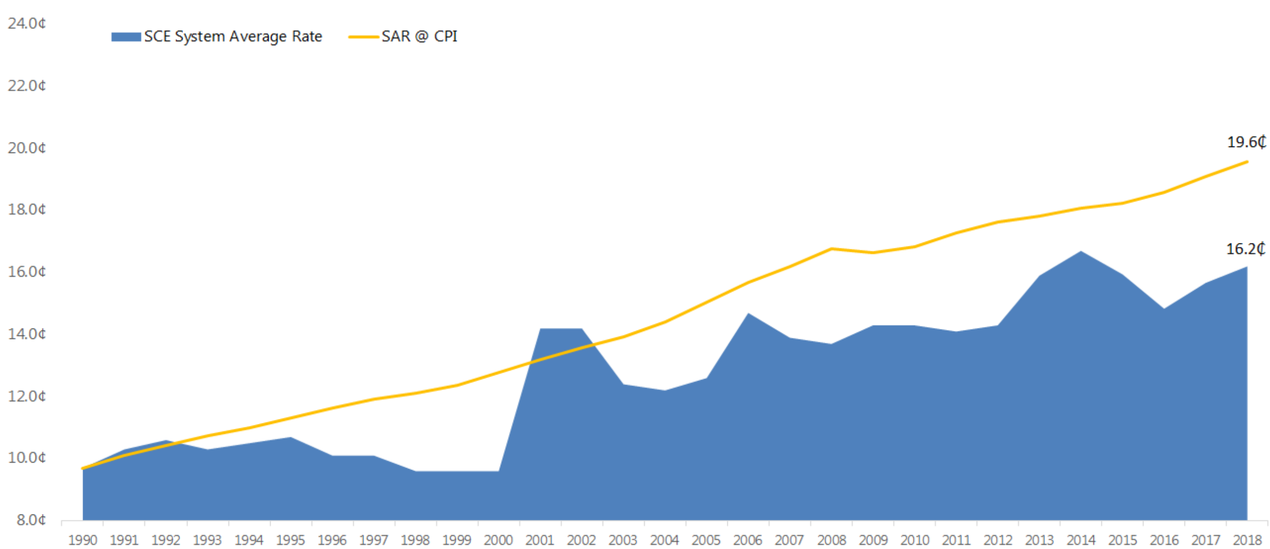
The information provided includes SCE's overall rate policy, a discussion of SCE management's policies and practices to control costs and rate increases for customers, and a discussion of SCE's policies and recommendations for limiting rate increases while meeting the State's energy and environmental goals for reducing greenhouse gases.

In addition, SCE has provided data contained in Appendix A to this Report that describes SCE's revenue requirements and provides an outlook for pending revenue requirement and rate changes from May 1, 2018 to April 30, 2019.

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 marginal 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]



[1] CPI based on US Bureau of Labor Statistics for all urban consumers in LA-Riverside-Orange County, CA.

At the customer class level, SCE establishes its revenue allocation and rate design based on marginal costs of service associated with each respective class. By applying cost of service principles, more revenue is recovered from customer classes that contribute to a higher level of utility's cost of service. Conversely, less is recovered from customer classes that have a lower cost impact to the utility. This general methodology helps to reduce the transfer of costs across and within customer classes, and is rigorously reviewed in each GRC Phase 2 proceeding.

In SCE's 2015 GRC Phase 2 proceeding (A.14-06-014), Parties settled on a proposal that resulted in a level of cost transfers across and within customer classes that was lower than what it was before, and provided some measure of rate stability for affected classes. In this particular instance, Parties agreed to a three-year phase out of an Agricultural and Pumping rate provision, which provided customers a ten-year discounted rate, in exchange for converting their water pumps from internal combustion to electric motors to reduce statewide emissions levels. A multi-year phase out policy, rather than the abrupt elimination, of a program that would have otherwise expired at the end of December 2015 is an example of balancing rate impacts from participating customers with the shift of undue revenue responsibility to non-participating customers. The phase out of rate benefits for these agricultural customers ended on January 1, 2018.

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 up to 2017 are based on billed operating revenues and sales. Data for 2018 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
2018 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	[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	18.2	
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	17.8	
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	19.0	
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	17.9	
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	15.9	
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	17.3	
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	14.2	
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	12.9	
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	8.7	
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	12.3	
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	14.6	[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	12.1	[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	13.5	
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	18.6	
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	14.6	
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	13.9	
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	8.7	
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	10.2	
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	16.2	

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2018 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
SB 695 Report To Energy Division
Year: 2018

Table 2

Historical Average Rates by Rate Group (2016 ¢/kWh) Based on Recorded Revenue and Sales
2018 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 [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	17.5	
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	17.1	
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	18.2	
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	17.2	
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	15.2	
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	16.6	
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	13.6	
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	12.4	
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	8.4	
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	11.8	
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	[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	[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	12.9	
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	17.8	
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	14.0	
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	13.3	
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	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	9.4	10.4	10.7	7.3	8.7	9.8	
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	15.6	
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	0.96	

[1] Forecasts calculated from Present Rate Revenues ("PRR") from 2018 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.

Table 3

Historical Average Rates by Rate Group (% of System Average Rate) Based on Recorded Revenue and Sales
2018 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	[1]
Domestic	118%	115%	114%	104%	96%	99%	103%	104%	108%	109%	109%	109%	108%	110%	113%	111%	104%	106%	112%	110%	112%	
TOU-GS-1	125%	122%	120%	130%	125%	122%	121%	123%	121%	126%	123%	120%	122%	122%	125%	117%	116%	115%	110%	109%	110%	
TC-1	76%	74%	74%	83%	96%	96%	99%	93%	92%	96%	100%	103%	110%	112%	111%	113%	118%	122%	124%	118%	117%	
TOU-GS-2	103%	103%	100%	106%	110%	109%	109%	109%	107%	103%	104%	106%	110%	108%	106%	108%	111%	111%	110%	110%	110%	
TOU-GS-3	100%	90%	102%	105%	105%	100%	97%	87%	94%	102%	102%	102%	95%	93%	91%	96%	101%	101%	98%	98%	98%	
Sm. and Medium Comm.	107%	106%	104%	110%	113%	111%	111%	110%	107%	107%	107%	107%	108%	107%	106%	107%	110%	109%	107%	107%	107%	
TOU-8-Sec	84%	83%	87%	98%	102%	98%	92%	92%	90%	90%	90%	91%	91%	89%	87%	91%	95%	95%	88%	89%	87%	
TOU-8-Pri	75%	74%	79%	87%	92%	89%	84%	86%	86%	85%	86%	83%	82%	81%	77%	81%	84%	84%	77%	78%	79%	
TOU-8-Sub	51%	52%	56%	67%	67%	65%	61%	61%	62%	60%	59%	56%	56%	54%	50%	54%	58%	58%	45%	52%	54%	
Large Power	70%	72%	77%	85%	90%	87%	82%	81%	81%	79%	79%	78%	77%	75%	72%	78%	82%	82%	73%	76%	76%	
PA-1	133%	122%	120%	115%	109%	115%	115%	122%	125%	121%	127%	127%	135%	138%	131%	82%	92%	88%	90%	93%	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%	75%	[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%	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%	114%	
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%	90%	
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%	86%	
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%	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%	63%	
Total System	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 2018 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[2] 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. 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 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

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

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

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. But these policy goals cannot be achieved by the electric sector alone.

The electric sector 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-prong 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 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 2018 system average rate remains below peak rates in the early 2000's. SCE's 2018 rate may decline further due to the pending SONGS OII Settlement Joint Motion[3], such that the final 2017 to 2018 change may be minimal.

APPENDIX A

1. **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, coal, 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

[3] On January 30, 2018, the parties in I.12-10-013 filed a Joint Motion for Adoption of Settlement Agreement which resolves all issues in this OII which would order SCE, among other items, cease collection of the SONGS OII revenue requirement in rates.
[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.

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. Since January 1, 2015, SCE is also recovering the revenue requirement associated with the SONGS 2 & 3 Order Instituting an Investigation (OII) Settlement Revenue Requirement in generation rates. [5]

b. **Cost Responsibility Surcharge** – Through the CRS, SCE recovers from customers that have elected to purchase their generation service from other providers (e.g. Direct Access (DA) customers), the above market costs of the combined SCE and DWR generation portfolios. The revenue generated from the CRS is credited back to 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 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.

[5] On January 30, 2018, the parties in I.12-10-013 filed a Joint Motion for Adoption of Settlement Agreement which resolves all issues in this OII which would order SCE, among other items, cease collection of the SONGS OII revenue requirement in rates.

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, Self-Generation Incentive 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.[6]

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 programs, 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

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

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 2018 is zero. In 2018, the DWR Bond Charge remains at the 2017 level of approximately $0.005/kWh.

2. Summary of Revenue Requirements by Rate Component

The table below shows SCE's Total System Revenue Requirements and Bundled System Average Rate for Bundled Service customers as of January 1, 2018:

1/1/2018

Rate Component	Total System $ Millions	Total System %	Bundled SAR c/kWh
Generation	5,588	45.9%	7.8
New System Generation	398	3.3%	0.5
Distribution (inc. GHG revenue)	4,318	35.5%	5.6
Public Purpose Programs	475	3.9%	0.6
Nuclear Decommissioning	4	0.0%	0.0
FERC Transmission	968	8.0%	1.2
DWR Power and Bond	411	3.4%	0.5
Total	12,163	100.0%	16.2

3. Sales Forecast

SCE's 2018 total sales forecast of 83,227 GWhs was approved in D.17-12-018, SCE's 2018 ERRA Forecast Proceeding. This represents a decrease from recorded 2017 sales (85,601 GWhs) of approximately 2.8%.

Southern California Edison Company
SB 695 Report To Energy Division
Year: 2018

Outlook from May 1, 2018 to April 30, 2019

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation Date	Requested Dollar Amount ($millions)		Description	Impacted Rate Component
				2018 RRQ	2019 RRQ		
2018 GRC	A.16-09-001	9/1/16	1/1/19	$5,673*	$6,150*	2019 Attrition year increase in O&M and capital revenue requirement	Generation, Distribution, and New System Generation
2019 ERRA Forecast (Includes GHG Costs and Revenue Return)	TBD	5/1/18	1/1/19	$4,576	TBD	Recovery of estimated fuel and purchased power costs	Mostly Generation, but also New System Generation, Distribution and Public Purpose
Transportation Electrification/ Standard Review Program	A.17-01-020	1/20/17	1/1/19	-	$15	Transportation Electrification infrastructure and incentives	Distribution
Charge Ready Phase 2	A.14-10-014	TBD	TBD	-	TBD	May involve a bridge funding application in addition to a the larger Phase 2	Distribution
Mobilehome Park Utility Upgrade Program	TBD	TBD	TBD	-	TBD	Four-year continuation of the CPUC approved MHP Pilot	Distribution
Energy Efficiency	A.17-01-013	1/17/17	6/1/18	$300	$271	10 year rolling portfolio of EE funding	Public Purpose
CEMA	Application	TBD	1/1/19	_	$48	Catastrophic Event Memorandum Account	Distribution
Aliso Canyon Utility Owned Energy Storage	A.17-03-020	3/30/17	6/1/18	$13	$13	Tesla and GE Utility Owned Energy Storage Cost Recovery	New System Generation
FERC Formula Rate Change	N/A (Advice Letter)	Nov. 2018	1/1/19	$1,163	TBD	Base Transmission Revenue	Transmission
Cost of Capital	TBD	April 2019	1/1/20	($80)	($85)	Filing pursuant to D.17-07-005	Generation, Distribution, and New System Generation
FERC Transmission Balancing Accounts	N/A (Advice Letter)	May (TACBAA) and Oct. 2018 (RSBAA and TRBAA)	6/1/18 and 1/1/19	($195)	TBD	Balancing Accounts	Transmission
DWR – Power and Bond Charge	TBD	Dec. 2018	1/1/19	$411	TBD	Bond Charge	Generation

*These amounts do not reflect the impact of Federal Tax Reform.